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EVALUATION OF R & D INVESTMENT ALTERNATIVES FOR SO_x AIR POLLUTION CONTROL PROCESSES, PART 2

S. Caceres, et al

The M. W. Kellogg Company
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The report gives results of an extension of work done in Part 1 of the study, reported in September 1974. Of the five major sources of sulfur oxide emissions studied in Part 1, new or enlarged data bases are presented for three: utility plants, industrial boilers, and sulfuric acid plants. Cost models developed for the wet limestone process and the Wellman/Allied process are applied to these source groups, and the results summarized. Application of the Wellman/Allied system to Claus plants is also discussed. Economics are shown for a 'packaged' limestone scrubbing system for small industrial boilers. Cost models, derived from the model for substitute natural gas plants developed in Part 1, are included for low-Btu and intermediate-Btu gas plants. Production costs of substitute natural gas, low-Btu gas, and solvent refined coal are presented, based on actual coal prices in the U.S.

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1. INTRODUCTION

The work reported herein represents Part 2 of a two part study which investigated the technical and economic aspects of a variety of technologies that could be used for the control of sulfur oxides from existing stationary sources. The study was done for the Office of Research & Development, Environmental Protection Agency, under Task 23, Contract No. 68-02-1308. Primarily, the work was intended to provide EPA with sufficient cost information to be helpful in determining effective, meaningful, and reasonable sulfur oxide control regulations for stationary sources. As an additional objective, it was also intended to provide guideline information to EPA for allocating its annual development budget.

Part 1 consisted of an investigation of the major sulfur oxide pollution sources, and a technical and economic assessment of various desulfurization techniques applicable to these sources. Specifically, the following source groups were studied:

1) Utility plants
2) Industrial boilers
3) Sulfuric acid plants
4) Sulfur (Claus) plants
5) Nonferrous smelters

Available information on each source group was reviewed and plants were characterized according to emission levels, plant capacity, type of fuel or feed, age, load factor, and geographical distribution. Statistical distributions were generated illustrating the variation of different plant parameters over the plant population for each source group.

Distributions of actual sulfur oxide emissions were also determined for each group. The sources, thus characterized, formed the basis for the investigation of desulfurization techniques.

Control technologies studied included the following:

1) Flue gas desulfurization
2) Fuel conversion processes
3) New power plant designs

The wet limestone process and the Wellman-Lord/Allied Chemical combined process were selected as being representative of throwaway and regenerable processes, respectively, for flue gas desulfurization. Fuel conversion processes studied included a process to convert coal to substitute natural gas via Lurgi gasification, and a process for solvent refined coal. In the area of new power plant designs, both a combined cycle plant, using Lurgi low Btu gas, and a pressurized, fluidized bed combustor were investigated.

Each process was reviewed for technical merit and feasibility, and process models were developed. These models basically set the processing sequence, process design, and process variables. Cost models were then developed which relate the important process variables to capital and operating costs. After establishing the cost models, the cost of installing flue gas desulfurization systems for existing utility plants was investigated. Additionally, costs of substitute natural gas and solvent refined coal were investigated and compared.

The results of the previous work are reported in "Evaluation of R&D Investment Alternatives For SO_2 Air Pollution Control

Processes - Part I" (EPA-650/2-74-098). The reader is referred to that report for detailed information.

Part 2 of this study is an extension of the work of Part 1. It consists of three prime areas of investigation:

1) a re-investigation of plant and emissions data to obtain new or enlarged data bases.

2) Determination of flue gas desulfurization costs, based on the revised data bases.

3) Extension of the work on fuel conversion to include additional processes, and further cost comparisons of the different technologies.

New data on utility boilers, consisting of a tape containing Federal Power Commission (FPC) Form 67 information, were obtained from EPA. This information was edited and validated to obtain a new data base for use in estimating flue gas desulfurization costs. Additionally, a NEDS (National Emissions Data System) tape, containing information on industrial boilers, was also obtained from EPA. These data, after editing and validating, formed the data base for the flue gas desulfurization cost analysis of industrial boilers. The sulfur (Claus) plant data base was upgraded with NEDS information to include, where available, the number of reaction stages in each plant. The sulfuric acid data base was also expanded to include gas flows and SO_x levels for each plant.

Using the revised data bases discussed above, flue gas desulfurization costs were determined and summarized for existing utility plants, industrial boilers, and sulfuric acid plants. Both scrubbing systems were included in the cost analysis for utility plants and industrial boilers. For the latter, this required some revisions to the cost models, due to the small size of many of the industrial boilers. Costs were also developed for a "packaged" wet limestone scrubbing system applied to a small industrial boiler to determine whether maximized shop fabrication would significantly lower costs for these small units.

Scrubbing costs were determined for acid plants, using a modified form of the Wellman/Allied cost model adapted specifically for application to acid plants. This cost model was also reviewed to determine what changes were necessary to adapt it to Claus plant applications.

The substitute natural gas (SNG) model developed in Part 1 of this study served as a basis for two new cost models: intermediate Btu gas, and low Btu gas. Costs were determined for SNG, low Btu gas, and solvent refined coal based on actual coal prices in different parts of the country.

2. SUMMARY AND CONCLUSIONS

2.1 SO_x Emission Sources

Input data obtained from EPA on utility boilers (Federal Power Commission Form 67 for 1971) contains information on 205 utilities, 689 plants, and 2798 boilers. After checking the raw data, it was found that 418 plants, containing 1555 boilers, required no editing. The final data base, selected for cost analysis of flue gas desulfurization, includes 417 plants. Although this is a smaller data base than used in Part 1 of this study (881 plants), it should be more reliable since it is based on actual plant data.

The National Emission Data System tape for industrial boilers contains information on 5685 plants having a total of 12,047 boilers. About 72% of the plants and 84% of the boilers are exclusively fired by either coal, oil, or gas. It was found that only 3991 plants and 4562 boilers had no major errors in the raw data. Only 3866 plants and 4106 boilers required no editing at all.

SO_x emmisions were estimated for all sulfuric acid plants in the data file from Part 1 and incorporated into the file. It was found that sulfuric acid mist constitutes an important part of the total emissions from an acid plant, being as high as 40% of the total emissions. This is significant from the point of view of designing a tail gas desulfurization unit, since acid mist particles tend to be small, stable, persistent, and difficult to remove.

The data file for Claus plants was upgraded to include the number of catalytic stages for each plant. Since emissions can be estimated on the basis of feed composition (H_2S concentration) and number of stages, future inclusion of feed composition in the data base is highly desirable. At present, no such information is available. For plants having 1-3 catalytic stages and H_2S feed concentrations of 15-90 mole %, emissions have been estimated to be 0.79-0.39 tons SO_2/long ton of sulfur.

2.2 Cost of Stack Gas Scrubbing

2.2.1 Utility Plants

Little difference was found for scrubbing costs between the wet limestone process and the Wellman/Allied system. For existing utility plants, capital costs averaged from about $200/KW for plants of 40 MW size to approximately $40/KW for 3000 MW plants. Operating costs for these plant sizes ranged from 10 mills/KWH for the smaller plant to 2 mills/KWH for the large plant.

Based on the total plant capacity included for cost analysis approximately 80% of the capacity could be controlled for less than $100/KW. About 90% of the power production from these plants could be controlled at costs of under 6 mills/KWH. An 80% reduction in sulfur emissions could be achieved at a total capital cost of approximately 2500 MM$ and a total operating cost of 500 MM$/year. Beyond 80%, costs increase sharply for further emission reductions.

2.2.2 Industrial Boiler Plants

Of the total of 4385 industrial boiler plants considered for cost analysis, only 829, or 19%, require control. For existing plants, capital costs averaged about $0.8/ MM Btu/year (based on total annual capacity) for plants in the size range of 10,000 MM Btu/hour to $2.4/MM Btu/year for plants of 100 MM Btu/hour capacity. Operating costs averaged from $0.2/MM Btu for 3000 MM Btu/hour plants to $1.8/MM Btu for plants having capacities of 100 MM Btu/hour. For plants with capacities under 100 MM Btu/hour, both capital and operating costs increase sharply with decreasing plant size.

Based on the number of plants requiring control, about 95% of the industrial boiler plant capacity could be controlled for capital costs of less than $3.0/MM Btu/year. 95% of the total plant production could be controlled at operating costs under $1.5/MM Btu.

The cost of a packaged limestone scrubbing system for a 50 MM Btu/hour boiler was estimated to be about $8/MM Btu/year. Operating costs are more than $3/MM Btu. These costs are lower (by about 20%) than those estimated for a normal field-erected installation for small boilers, but the exact magnitude of the cost savings is uncertain, due to the accuracy of the estimating techniques employed.

2.2.3 Sulfuric Acid Plants

For existing sulfuric acid plants, tail gas scrubbing capital costs averaged from $58/ton of annual acid capacity (100% acid) for plant capacities of 10 M tons/year to about $10/ton of annual acid capacity for 1800 M ton/year plants. The corresponding operating costs are $17/ton of acid for the smaller plant and $4/ton of acid for the larger plant. About 90% of the total sulfuric acid plant capacity could be controlled for capital costs of less than $30/ton of annual capacity, while the same percentage of total production could be controlled for operating costs of under $9/ton of acid. Control of more than 90% of the total plant capacity or production causes a substantial increase in costs.

2.2.4 Sulfur (Claus) Plants

A review of the Wellman/Allied model showed that a number of changes should be made in order to apply it to treatment of tail gas from a Claus plant. A major change is that the Allied section of the system is no longer needed since the recovered SO_2 from the Wellman-Lord section could be recycled directly as feed to the Claus unit. Additionally, since the incinerated tail gas (After cooling) is saturated with water vapor and contains no fly ash, no prescrubbing section is needed. The higher SO_2 concentrations in the tail gas, relative to typical concentrations in boiler flue gas, would also suggest a re-design of the absorber to a more conventional, and perhaps less expensive, configuration.

2.3 Cost of Fuel Conversion

2.3.1 Substitute Natural Gas

Based on reported coal prices, the cost of SNG has been estimated to vary from a low of $1.14/MM Btu to a high of $2.67/MM Btu. These costs correspond to mine-mouth coal prices of $1.90/ton and $25.61/ton. SNG production costs tend to be the highest in eastern states and the lowest in Rocky Mountain states, primarily due to the difference in coal prices.

2.3.2 Intermediate Btu Gas

The process and cost model for an imediate Btu gas plant is based on the SNG model from Part 1 and corresponds to a plant capacity of 125×10^9 Btu/day. The model predicts total capital requirements for the plant to be about 150-170MM$. Intermediate Btu gas production costs vary from $1.17-1.65/MM Btu, depending on coal costs ($8-12/ton), coal analysis, and plant location.

2.3.3 Low Btu Gas

The process and cost model for a low Btu gas plant is also based on the SNG model from Part 1 and also is sized for 125 MM Btu/day. Total capital requirements are predicted to be 120-130MM$. Production costs are estimated at $1.00-1.45/MM Btu, depending upon coal costs ($8-12/ton), coal analysis, and plant location.

2.3.4 Solvent Refined Coal

Based on estimated mine-mouth coal prices of $1.90-15.05/ton, production costs for solvent refined coal have been estimated at $0.64-1.31/MM Btu. For equivalent fuel (coal) prices, SRC costs are about 55-60% of the cost of SNG. As with SNG, the most significant cost variable is the cost of coal.

3. DESULFURIZATION PROCESSES

A variety of desulfurization processes were investigated in Part 1 of this study, and these form the basis of much of the work reported here. In order to acquaint the reader who is unfamiliar with Part 1, a brief review and description is provided for each process.

3.1 Flue Gas Desulfurization

Two flue gas desulfurization processes were investigated: the wet limestone process and the Wellman-Lord/Allied Chemical process. These were chosen as being representative of the throwaway and regenerable scrubbing processes, respectively, and because they are the most commercially advanced of the flue gas desulfurization technologies.

The wet limestone process, illustrated in Figure 3.1, is based on the Catalytic, Inc. design (3) with some process modifications made by Kellogg. Flue gas is contacted with a recirculating limestone slurry in a dual scrubbing system, consisting of a venturi followed by a turbulent contact absorber (TCA), to cool and saturate the gas and to remove sulfur oxides. The gas passes through a water-washed entrainment separator, is heated in a direct-fired reheater to establish buoyancy, and finally compressed before discharge to the stack. Make-up limestone is ground and slurried before being added to the scrubbing system. Waste solids from the scrubbing systems are sent to a settling pond for disposal.

Figure 3.2 shows the process flow sheet for the Wellman/Allied system. The design is based on the demonstration plant now under construction at the D.H. Mitchell plant of the Northern

Indiana Public Service Company, with some process modifications made by Kellogg. Flue gas is cooled and saturated in a prescrubber after which it is contacted with a sodium sulfite solution for SO_2 removal. The clean gas is reheated and recompressed prior to discharge to the atmosphere. SO_2 is regenerated from the spent solution from the absorber by evaporation/crystallization of the liquor. The SO_2 is purified by condensation of water and steam stripping of the condensate after which it is converted to elemental sulfur via reaction with natural gas in the Allied Chemical section of the process. A purge system is necessary to remove and process oxidation products, while a make-up system replenishes sodium values lost in the purge stream.

3.2 Substitute Natural Gas

The model developed for substitute natural gas (SNG) is based on Lurgi pressure gasification of coal with steam and oxygen. The actual designed was obtained from information in the literature (5) and Kellogg sources (9).

The process flow sheet is shown in Figure 3.3. Coal from storage is crushed and classified, with the sized material being sent directly to the gasifiers. Fines produced from grinding are sent either to a boiler (equipped with a stack gas scrubbing unit), which provides process steam and power requirements, or to a fines agglomeration unit, from which the agglomerated coal is fed to the gasifiers. In the gasifiers, coal is reacted with steam and oxygen. The latter is supplied by an on-site oxygen plant. Raw gas from gasification undergoes shift reaction to adjust the H_2/CO ratio, followed by cooling prior to the purification step. Phenols and tars condensed by gas cooling are recovered in a Phenosolvan unit and recycled as fuel to the boiler. Purification consists of removal of most of the CO_2 and virtually all of the H_2S. H_2S from purification is sent to a Claus plant for conversion to elemental sulfur. The purified gas is methanated over a nickel catalyst, after which final CO_2 removal is effected to upgrade the gas to pipeline quality. The product gas is then compressed for delivery to the pipeline.

3.3 Solvent Refined Coal

The solvent refined coal process, illustrated in Figure 3.4, is based on a Stearns-Roger report for the Pittsburg and Midway Coal Mining Company, (17,18), with some process modifications made by Kellogg. After crushing and grinding, the raw coal is sent to flash dryers where the moisture is removed. The dried coal is dissolved in a solvent (anthracene) in the presence of hydrogen, which is supplied by reforming recycled light oil. Dissolution of the coal involves both hydrogenation and depolymerization reactions. Ash is removed from the dissolved coal by filtration after which it is dried, to recover residual solvent, and sent to storage. Solvent and light oils are recovered and purified through flash separation and distillation. Solvent is recycled to the dissolving section while the light oil, after sulfur removal and recovery, is used both as feed to the hydrogen plant and as fuel to a boiler which supplies process steam and power requirements. The major by-product of the purification step is cresylic acid. Finally, the liquefied coal is solidified and transferred to storage. Alternately, the coal could be kept in a liquefied state, but this requires keeping it hot.

FIGURE 3.1

WET LIMESTONE PROCESS FLOWSHEET

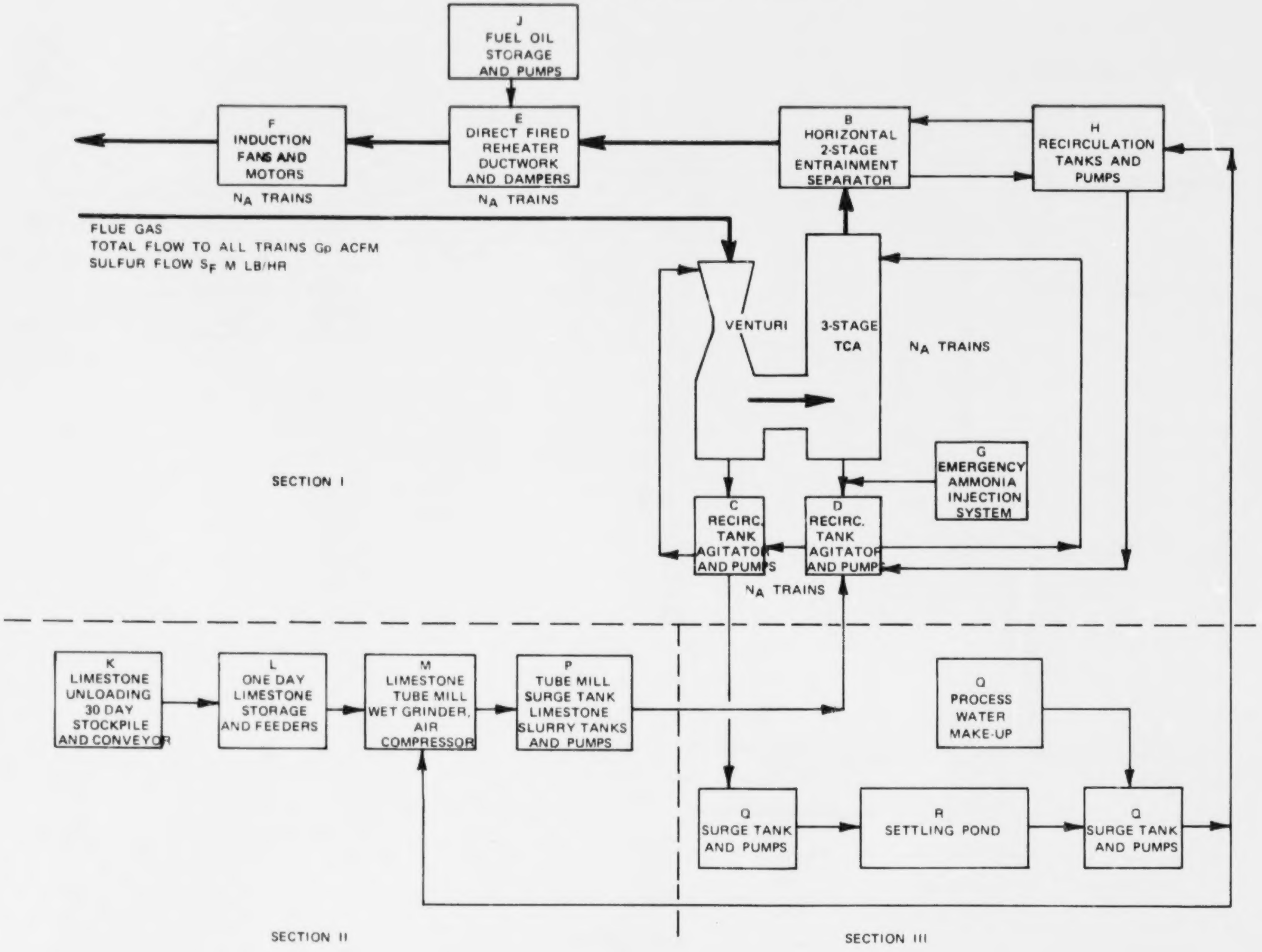

J
FUEL OIL
STORAGE
AND PUMPS
F
INDUCTION
FANS AND
MOTORS
N_A TRAINS
E
DIRECT FIRED
REHEATER
DUCTWORK
AND DAMPERS
N_A TRAINS
B
HORIZONTAL
2-STAGE
ENTRAINMENT
SEPARATOR
H
RECIRCULATION
TANKS AND
PUMPS
FLUE GAS
TOTAL FLOW TO ALL TRAINS G_p ACFM
SULFUR FLOW S_F M LB/HR
VENTURI
3-STAGE
TCA
N_A TRAINS
SECTION I
G
EMERGENCY
AMMONIA
INJECTION
SYSTEM
C
RECIRC.
TANK
AGITATOR
AND PUMPS
D
RECIRC.
TANK
AGITATOR
AND PUMPS
N_A TRAINS
K
LIMESTONE
UNLOADING
30 DAY
STOCKPILE
AND CONVEYOR
L
ONE DAY
LIMESTONE
STORAGE
AND FEEDERS
M
LIMESTONE
TUBE MILL
WET GRINDER,
AIR
COMPRESSOR
P
TUBE MILL
SURGE TANK
LIMESTONE
SLURRY TANKS
AND PUMPS
Q
PROCESS
WATER
MAKE-UP
Q
SURGE TANK
AND PUMPS
R
SETTLING POND
Q
SURGE TANK
AND PUMPS
SECTION II
SECTION III

FIGURE 3.2

WELLMAN/ALLIED PROCESS FLOWSHEET

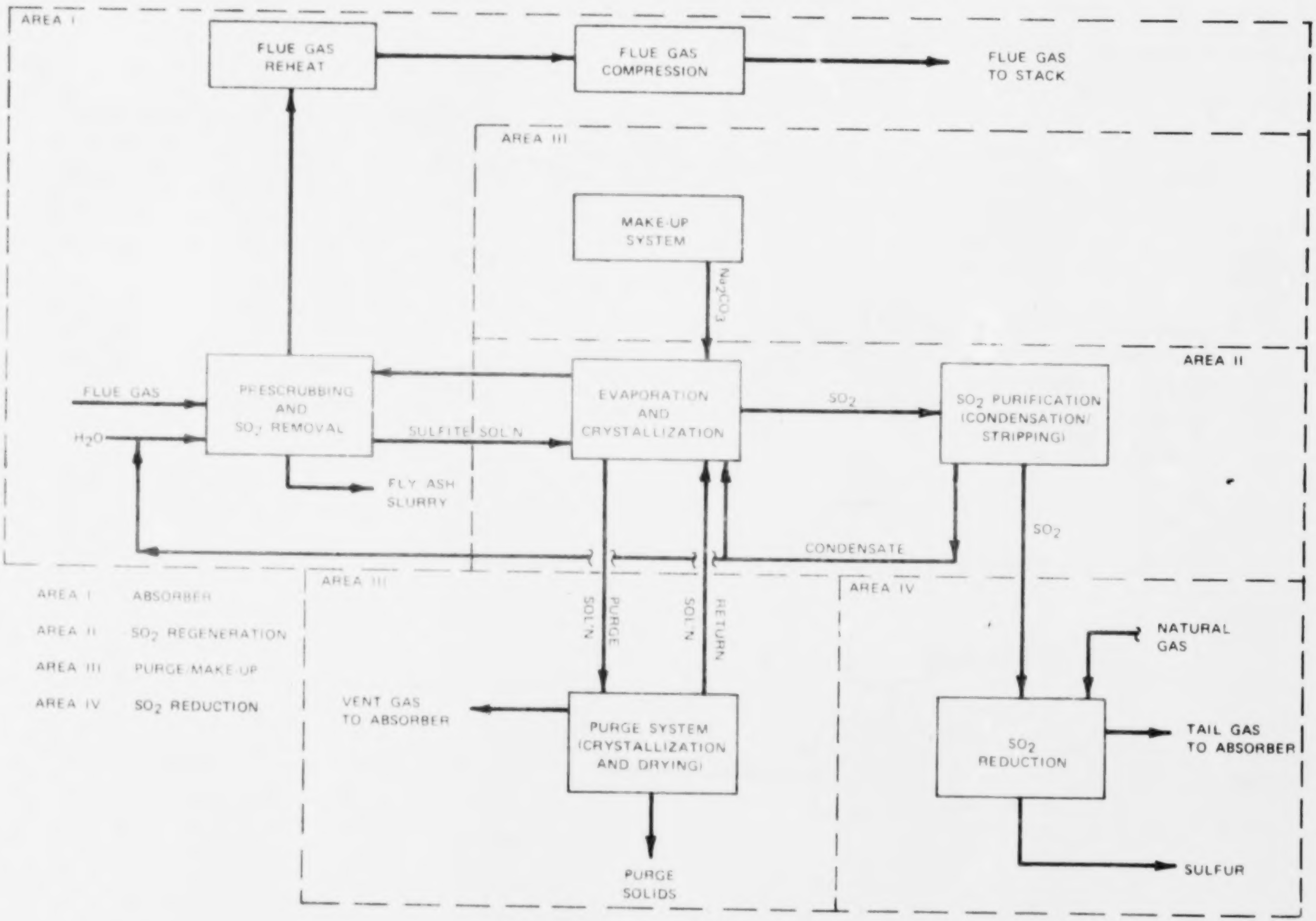

AREA I
FLUE GAS REHEAT
FLUE GAS COMPRESSION
FLUE GAS TO STACK
AREA III
MAKE-UP SYSTEM
Na_2CO_3
AREA II
FLUE GAS
H_2O
PRESCRUBBING AND SO_2 REMOVAL
SULFITE SOL'N
FLY ASH SLURRY
EVAPORATION AND CRYSTALLIZATION
SO_2
SO_2 PURIFICATION (CONDENSATION/STRIPPING)
SO_2
CONDENSATE
PURGE SOL'N
RETURN SOL'N
AREA III
AREA IV
VENT GAS TO ABSORBER
PURGE SYSTEM (CRYSTALLIZATION AND DRYING)
PURGE SOLIDS
NATURAL GAS
SO_2 REDUCTION
TAIL GAS TO ABSORBER
SULFUR
AREA I ABSORBER
AREA II SO_2 REGENERATION
AREA III PURGE/MAKE-UP
AREA IV SO_2 REDUCTION

FIGURE 3.3

LURGI SNG PROCESS FLOW DIAGRAM

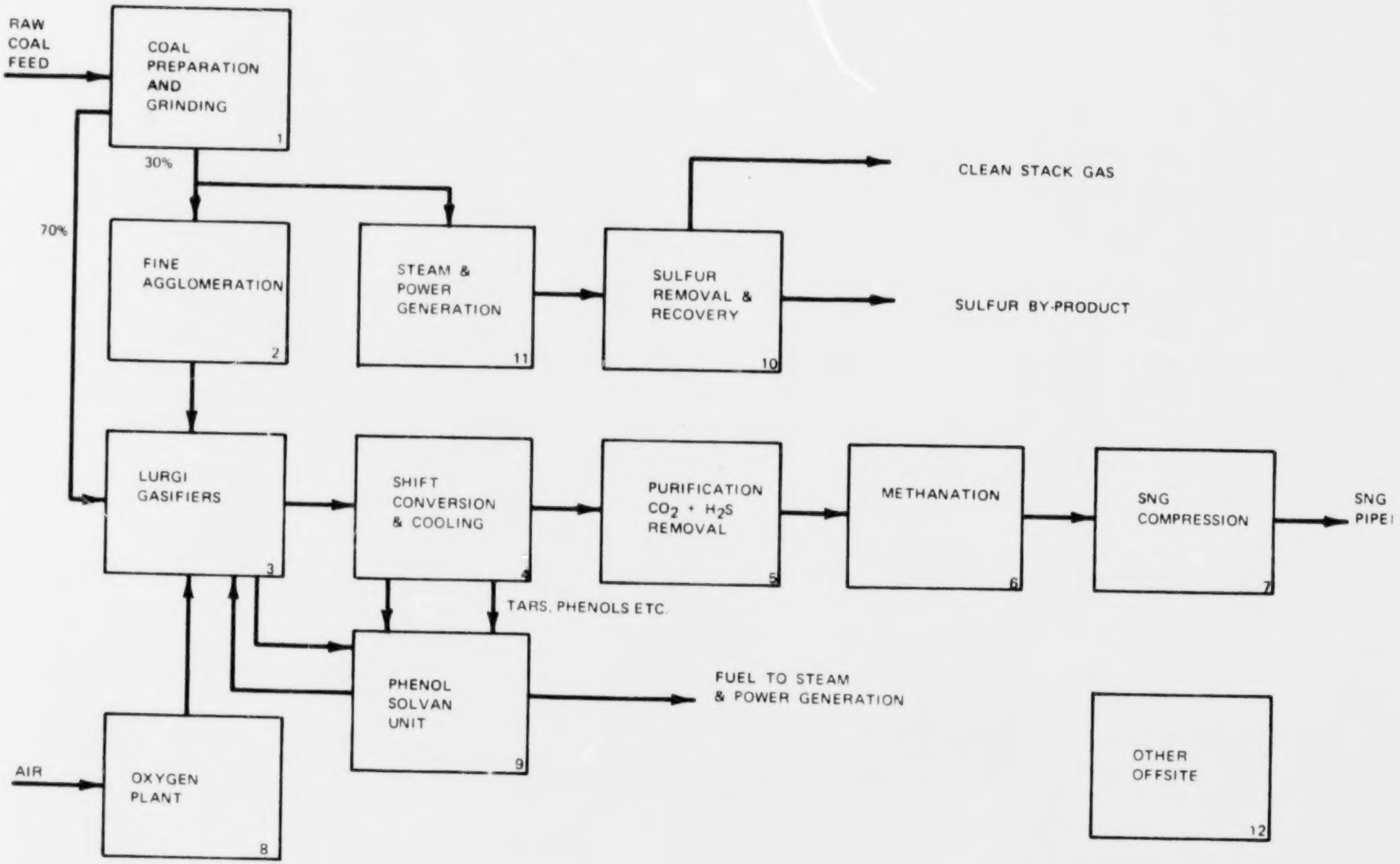
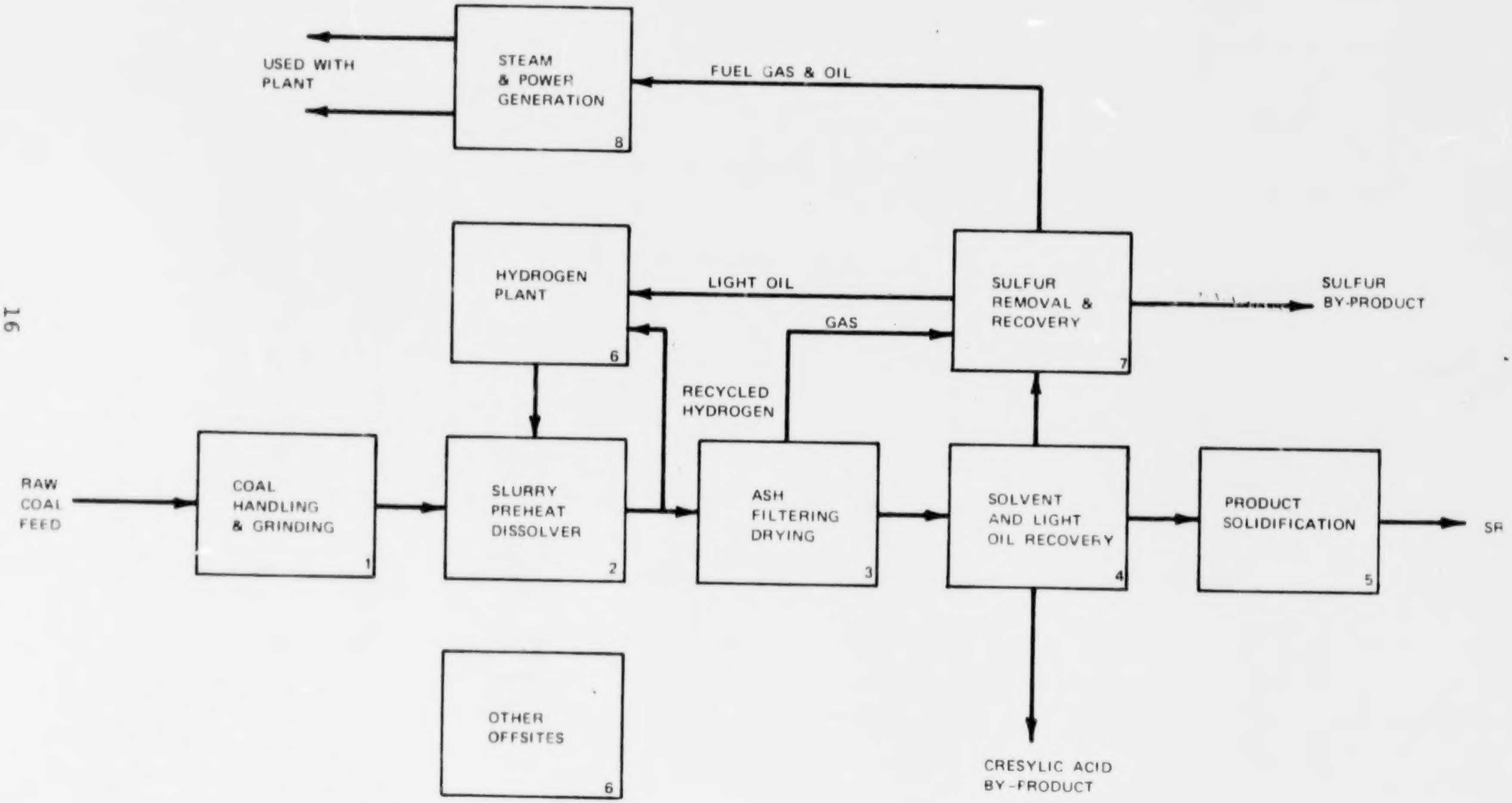

RAW
COAL
FEED
COAL PREPARATION AND GRINDING 1
30%
70%
FINE AGGLOMERATION 2
STEAM & POWER GENERATION 11
SULFUR REMOVAL & RECOVERY 10
CLEAN STACK GAS
SULFUR BY-PRODUCT
LURGI GASIFIERS 3
SHIFT CONVERSION & COOLING 4
PURIFICATION $CO_2 + H_2S$ REMOVAL 5
METHANATION 6
SNG COMPRESSION 7
SNG
PIPE
TARS, PHENOLS ETC.
PHENOL SOLVAN UNIT 9
FUEL TO STEAM & POWER GENERATION
AIR
OXYGEN PLANT 8
OTHER OFFSITE 12

FIGURE 3.4

SOLVENT REFINED COAL PROCESS FLOW DIAGRAM


USED WITH PLANT
STEAM & POWER GENERATION
8
FUEL GAS & OIL
HYDROGEN PLANT
6
LIGHT OIL
GAS
SULFUR REMOVAL & RECOVERY
7
SULFUR BY-PRODUCT
RECYCLED HYDROGEN
RAW COAL FEED
COAL HANDLING & GRINDING
1
SLURRY PREHEAT DISSOLVER
2
ASH FILTERING DRYING
3
SOLVENT AND LIGHT OIL RECOVERY
4
PRODUCT SOLIDIFICATION
5
SR
OTHER OFFSITES
6
CRESYLIC ACID BY-PRODUCT

4. SO_x EMISSION SOURCES

4.1 Utility Plants

4.1.1 Upgraded Data Base for Utility Plants.

The cost statistics generated in Part 1 of this study used as its data base:

1. Actual data on the majority of the plants and

2. Data obtained by replacing erroneous or missing values with new values based on statistical distributions derived from the total boiler population. For example, incorrect boiler heat rates were replaced using a correlation, based on data for all boilers, between heat rate and boiler size. Appropriate substitutions were also made for other boiler parameters where necessary.

The major revisions that were made were with regard to the allocation of plant fuel to the individual boilers within each plant. The various assumptions with regard to the actual data base used in Part 1 are discussed in that report. In Part 2, costs for installing wet limestone and Wellman-Lord/Allied Chemical scrubbing on existing utility boiler plants were rerun and summarized using data available on FPC Form 67 for the year 1971. The magnetic tape containing data from Form 67 was supplied by EPA to Kellogg.

4.1.2 FPC Form 67 and the Creating of the Upgraded Data Base

FPC Form 67 is a questionnaire filed by the steam electric generating power plants with the Federal Power Commission and a copy of this form is included in

Appendix A. These forms are edited and processed for each year and the data are available on a magnetic tape. The tape supplied to Kellogg contained nearly 340,000 unique records.

The data base for 1971 contains data on:

205	utilities
689	plants
2798	boilers

The utilities and plants in the FPC Form 67 have been identified by a 6 and 4 digit numeric code respectively. As far as is known, there is no equivalence between the plant and utility codes as given in the FPC Form 67 and the identification codes in the data base used in Part 1 of this study. Table 4.1 shows the summary or errors related to the entire data base extracted from the FPC 67 data. Since a definite means to establish equivalence between the two data bases was not available, it was decided that the data base be solely extracted from the data supplied by EPA (FPC Form 67 for the year 1971).

4.1.3 Steps in Creating the Data Base

The creation of the data base was accomplished through the following steps:

1. Data Reduction - The data that were not needed by the cost analysis programs were dropped.

2. Data Extraction - All available data required for the cost analysis of stack gas scrubbing were extracted. Table 4.1.3 illustrates the data extracted for each plant.

3. Data Validation - In a number of plants data were missing for one or more boilers. The data base was validated by using suitable codes to indicate what data were available or missing for each plant and its individual boilers. These codes were used as the basis to either process the plant for cost analysis or exclude it. Table 4.4 shows the transformation to the data of an individual plant and its boilers to include the data validation codes.

4.1.4 Assumptions for Data Extraction & Data Validation

Certain basic assumptions had to be made in order to create the required data base. These include:

1. The data supplied on the FPC tape were already edited for proper sequence and were reported strictly as required by the questionnaire.

2. All data had been checked for magnitude errors and corrected where necessary.

3. All footnotes and comments about any data were ignored.

In order to improve the data base created from the raw input, data for individual plants and boilers were checked and validated. It must be pointed out that no statistical distributions were used to supply missing data either for plants or boilers. However, the following assumptions were made to validate the data base:

1. Whenever a boiler load factor was missing it was replaced by 67%.

2. Whenever the gas flow rate for a boiler within a plant was missing it was replaced using the average flow rate per unit capacity of the other boilers in the same plant as a basis.

3. If heating values for the fuels were missing they were replaced by standard values.

In a large number of plants (see Summary of Errors and Edits, Table 4.2) there were errors in the data that would result in an erroneous cost for flue gas desulfurization. For example, in certain plants the fuel consumption of a boiler was missing or the boiler size was not given. The Summary of Errors and Edits (Table 4.2) indicates exactly the quality of the data available from the data file used for this part of the study. It must be pointed out that a plant or a boiler could have more than one type of error.

For generating the various costs and cost curves only 417 utility plants have been included. This amounts to about 61% of the data available in the raw data base received from EPA. Additionally, utilities which do not use fuels from other states or do not transmit power to other states are not within the jurisdiction of the FPC and their data are not available on FPC Form 67.

By contrast, the number of plants considered in Part 1 of this study was 881.

4.1.5 Methods to Improve the Data Base

In order to upgrade and complete the data base created by using the FPC Form 67 it is necessary that all missing data be gathered and added to the data base. There are a number of utility plants which do not report to the FPC but must be accounted for in estimating the costs of the flue gas desulfurization. Following are some of the ways that could be used to get a more reliable data base:

a) Using the data extraction and validation system developed by Kellogg as part of this study, generate individual plant data reports (Table 4.4) and with this as the basis gather or correct all missing or invalid data by contacting individual utility companies.

b) Use other data sources on utility plants. These sources have been discussed in Part 1 of this study.

4.1.6 Effect of the Size of the Data Base On Cost

The objective of this study was to obtain certain cost statistics for applying stack gas scrubbing for the removal of SO_2 emissions from existing power plants in the U.S. In order to generate average costs and obtain a relationship between the plant size and investment, for example, a good sample of the utility plants throughout the country is required. The 417 plants which have formed the basis of the cost statistics is a reliable data base, containing actual data reported by the different utilities. However, if total investment or operating cost (for the U.S. or a particular state) are desired, then the figures reported here obviously will be unrealistic, since a large number of power plants have not been included in the study. Section 6.1 of this report discusses how each of the costs are affected by the amount of data considered.

4.2 Industrial Boilers

Industrial boilers in the United States constitute a major source of sulfur dioxide emissions and contributed approximately 13% of the total U.S. sulfur emissions in 1971.

4.2.1 Original Data Base From NEDS

Industrial boiler data were provided by EPA from NEDS (National Emissions Data System) on a magnetic tape. The tape received includes data for each individual plant and its boilers. The typical NEDS data input form is shown in Appendix B. Data for each plant include name, state, and county location with each individual boiler in the plant described by its capacity, emissions, flow rate and type of fuel burned.

The preliminary analysis of the data base received showed that 5685 plants are included which total 12,047 boilers. This gives an average of 2 boilers per plant, ranging from a minimum of 1 per plant to a maximum of 45.

4.2.2 Data Extraction Step

The data received were rearranged and stored on a tape. Computer programs have been used to extract boiler data, and a special subroutine was written to use the individual boiler data and arrive at the overall plant data. Individual boiler sizes are summed to give the plant size. Fuel consumption is calculated for each boiler and the total amount of fuel burned in the plant is determined. The sulfur emission from each boiler is calculated and the value obtained is compared to the value reported on NEDS data file tape.

Each boiler in a plant could burn more than one fuel. The types of fuel burned are determined by an 8-digit SCC number (Source Classification Code). A subroutine converts the SCC number to type of fuel used. The following fuels could be burned: coal, oil, gas, coke, wood, LPG, bagasse, and some nonclassified fuels. Boiler load factors are also calculated. In many cases important boiler data were not available from the NEDS data file and a subroutine was written to check and print out which ones were missing. (The correction for the missing data will be discussed in the next section.) Each plant, as well as each boiler, is assigned an error code which is used later in order to determine if a plant should be bypassed or not in the cost model.

The summary of the data extraction step gives the following fuel burning data breakdown:

1) For Plants

	Number in each category	Percent of total population
Plants burning only coal, oil or gas	4316	72
Plants burning only fuels other than coal, oil or gas	1026	17
Plants burning all types of fuel	669	11

2) For Boilers

Boilers burning only coal, oil or gas	9088	84

	Number in each category	Percent of total population
Boilers burning only fuels other than coal, oil or gas	679	6
Boilers burning all types of fuel	1085	10

A sample of the extracted plant and boiler data is shown in Table 4.5. The summary of errors related to plants and boilers is shown in Table 4.6.

4.2.3 Data Validation Step

The following corrections have been made for missing data values.

Corrections to Individual Plant Data

A plant is bypassed for the cost analysis program:

1) When its capacity is missing.
2) When the total fuel consumption is not available.
3) When there are zero boilers indicated for the plant.
4) When the plant has no boiler flow rates given.
5) When all boiler sizes are missing.

When the cost analysis program is applied, a choice can be made to bypass or include plants which use fuels other than coal, oil and gas.

Corrections to Individual Boiler Data

1) When the flow rate is missing for an individual boiler in a plant, the boiler flow rate is obtained by prorating from the available flow rates of the other boilers in that particular plant.

2) When the boiler load factor is zero, it is replaced by a value of 0.5.
3) When the boiler load factor is greater than 1.1 (probably due to some erroneous data), it is replaced by a load factor of 0.5.

A sample of the validated plant and boiler data report is shown in Table 4.7. The summary of the data validation step which gives the plant and boiler errors breakdown is shown in Table 4.8.

4.3 Sulfuric Acid Plants

Atmospheric emissions from sulfuric acid plants vary, both in quantity and composition, depending upon the process, the mode of operation, and the condition of the plant. The quantitative information on sulfur emissions from the various types of plants has been obtained from the report "Engineering Analysis of Emissions Control Technology for Sulfuric Acid Manufacturing Processes" prepared by Chemico (4), and has been classified as follows:

1) Chamber Acid Plants

Tail gas flow rate	130,000 SCF/ton of 100% acid
SO_2	0.02 tons S/ton of 100% acid
Acid Mist:	0.002 tons S/ton of 100% acid

2) Sulfur Burning Contact Plants (3 Conversion Stages)

Tail gas flow rate	92,000 SCF/ton of 100% acid
SO_2	0.02 tons S/ton of 100% acid
Acid mist:	
- 99% acid product	0.002 tons S/ton of 100% acid
- Oleum product	0.005 tons S/ton of 100% acid

3) Sulfur Burning Contact Plants (4 Conversion Stages)

Tail gas flow rate	90,000 SCF/ton of 100% acid
SO_2	0.012 tons S/ton of 100% acid
Acid mist:	
- 99% acid product	0.002 tons S/ton of 100% acid
- Oleum product	0.005 tons S/ton of 100% acid

4) Wet Gas Contact Plants (3 Conversion Stages)

Raw Material	Tail gas flow rate SCF/ton 100% acid	Sulfur Emission tons S/ton of 100% acid		
		as SO_2	as Mist	
			99% Acid	Oleum
H_2S	100,000	0.018	0.002	0.006
Pyrites	109,000	0.018	0.002	0.006
Acid sludge	109,000	0.018	0.003	0.007
Copper converter gas	192,000	0.027	0.004	0.011
Roaster gas	145,000	0.018	0.003	0.008

5) Wet Gas Contact Plants (4 Conversion Stages)

Raw Material	SCF/ton 100% acid	Sulfur Emission tons S/ton of 100% acid		
		as SO_2	as Mist	
			99% Acid	Oleum
H_2S	99,000	0.012	0.002	0.005
Pyrites	108,000	0.012	0.002	0.006
Acid sludge	117,500	0.012	0.003	0.006
Copper converter gas	184,000	0.018	0.004	0.010
Roaster gas	143,000	0.012	0.003	0.008

These values were used to determine the sulfur emissions for all (251) plants contained in the sulfuric acid plant data file developed in Part 1 of this study. The emission statistics are summarized in Fig. 4.1, 4.2, and 4.3.

Sulfuric acid mist constitutes an important fraction (9% to 40%) of the total sulfur emission from acid plants. It consists of small drops (1 to 5 microns in diameter) of sulfuric acid, usually over 90% concentration, formed in the vapor phase from water vapor and SO_3. Once formed, it is extremely stable and it is not readily separated or removed from the gas. A most persistent form of this mist is produced in most oleum plants. The important fact from a pollution standpoint is that this mist consists of much finer particles (0.2 to 3.0 microns) than those present in the normal mist produced in plants where oleum is not a product. For plants producing 98% acid, about 30% by weight of the particles are smaller than 2 microns.

4.4 Sulfur (Claus) Plants

The unrecovered sulfur appears in the Claus plant tail gas principally as H_2S, elemental sulfur, and SO_2 with lesser amounts of other sulfur compounds. Incineration of the tail gas is the method most often used to convert the unrecovered sulfur almost entirely to sulfur oxides.

The acid gas feed composition, number of catalytic stages, sulfur emission, and tail gas treatment, if any, are seldom published for U.S. plants. Therefore, there are no correlations available to determine the actual emissions from a plant, given its characteristics. Limited quantitative information can be obtained from the report "Characterization of Claus Plant Emissions" (19) which gives the amount of SO_2 released (as incinerator stack gas sulfur dioxide equivalents) as a function of the number of catalytic stages and the acid gas feed concentration as follows:

Number of Catalytic stages	Mole percent H_2S in acid gas feed	Stack gas SO_2 s.tons SO_2/l.ton of S product
1	90	
2	15	0.25
2	50	0.17
2	90	0.14
3	90	0.07

These values are plotted in Fig. 4.4.

The above mentioned report also gives a list of the plants that are operating in the U.S. and provides estimates of their emissions by assuming that:

a) The typical Claus plant has two catalytic stages.

b) The Claus sulfur production averages 60 percent of the rated plant capacity.
c) The Claus sulfur recovery averages 90 percent.

A data file on Claus plants was obtained from this information during Part 1 of this study. This file has now been upgraded to include the number of catalytic stages for some plants by cross-referencing the information with that contained in the NEDS file on Claus plants.

TABLE 4.1

SUMMARY OF ERRORS RELATED TO THE REDUCED DATA BASE

```
ERROR                    ERROR DESCRIPTION
TYPE/NUMBER                                                                                            NUMBER      ACTION
------------------------------------------------------------------------------------------------------ OF ERRORS   TAKEN
                                                                                                       -------------------
PLANT  ERRORS
-------------
    1          ANNUAL TOTAL FUEL CONSUMPTION FOR A PLANT IS MISSING
    2          SULFUR % FOR COAL NOT GIVEN                                                                19         MV
    3          SULFUR % FOR OIL NOT GIVEN                                                                  1         MA
    4          AVERAGE HEATING VALUE OF FUEL   NOT GIVEN                                                   3         MA
    5          PLANT STATE IS NOT GIVEN                                                                    4         MV
    6          PLANT CAPACITY IS NOT GIVEN                                                                 0         NA
    7          AJCR NUMBER IS NOT GIVEN                                                                    0         NA
    8          PLANT HAS ZERO NUMBER OF BOILERS REPORTED                                                   0         NA
                                                                                                          16         BP
BOILER ERRORS
-------------
    9          ANNUAL TOTAL FUEL CONSUMPTION FOR A BOILER MISSING
   10          TOTAL HOURS OF OPERATION FOR BOILER  MISSING                                              731         MV
   11          BOILER CAPACITY FACTOR IS MISSING                                                         107         ZE
   12          BOILER NUMBER IS NOT IN SEQUENCE -  NO BOILER DATA ON NEXT BOILER                         311         ZE
   13          BOILER SIZE IS NOT GIVEN                                                                    0         NA
   14          THE SULFUR EMISSION COMPUTED BY PGM  & SUPPLIED BY UTILITY NOT IN TOLERANCE  *            620         ZE
   15          FLUE GAS FLOW RATE IS MISSING FOR A GIVEN LOAD                                           1493         NA
   16          NO ANNUAL OR MONTHLY FUEL CONSUMPTION GIVEN FOR THE BOILER                               2563         ZE
                                                                                                         732         BP
PAGE   ERRORS
-------------
   17          COLUMNS OF PAGE NOT MATCHED
   18          STATE CODE IS GREATER THAN 51 OR EQUAL TO 40                                                0         BP
                                                                                                          54         NA



RECORD ERRORS
-------------
   23          FORM AT IDENTIFICATION IS IN CONFLICT WITH TYPE OF DATA ON RECORD
   24          ILLEGAL  CHARACTER IN DATA FILED                                                            0         BR
                                                                                                           0         BR

     LEGEND OF ACTIONS TAKEN
     ***********************
     NA   NO ACTION TAKEN
     ZE   ZERO VALUE ASSUMED
     MV   MONTHLY DATA USED TO OBTAIN ANNUAL VALUE
     MA   MONTHLY DATA USED TO OBTAIN AVERAGE VALUE
     BP   PAGE BYPASSED
     BR   RECORD BYPASSED

     TOLERANCE=10.00 OF EACH OTHER
```

TABLE 4.2

SUMMARY OF ERRORS & EDIT MADE TO THE UPGRADED UTILITY DATA BASE

Reproduced from
best available copy.

```
DATA VALIDITY        EXPLANATION OF DATA VALIDITY CODE                      NUMBER IN    ACTION
   CODE                                                                       CODE        TAKEN
-------------        ---------------------------------                    ---------    -------
  CODES FOR PLANTS
  ----------------                                                          PLANTS
                                                                            ------
      1              NO EDITING REQUIRED FOR PLANT DATA                      415          NA
      3              PLANT CAPACITY IS NOT GIVEN                               0          BP
      4              ANNUAL TOTAL FUEL CONSUMPTION NOT GIVEN                   0          BP
      5              PLANT HAS ZERO NUMBER OF BOILERS REPORTED                 0          BP
      6              NO GAS FLOW RATE GIVEN FOR ANY BOILER                     0          BP
      7              HEATING VALUES MISSING FOR FUEL                           4          BP
      8              CAPACITY FOR ALL BOILERS IN A PLANT IS MISSING            2          SB
      9              PLANTS WITH MAJOR ERRORS IN BOILER DATA                   0          BP
                                                                             260          BP
  CODES FOR BOILERS
  -----------------                                                         BOILERS
                                                                            -------
      0              NO EDITING REQUIRED FOR BOILER DATA                    1555          NA
      2              LOAD FACTOR MISSING REPLACED BY PLANT AVG OR 47%         34          SB
      3              BOILER SIZE IS MISSING                                  253          BP
      4              GAS FLOW RATE IS MISSING REPLACED BY PRORATING          200          SB
      5              NO GAS FLOW IS AVAILABLE FOR ANY BOILER                   0          BP
      6              FUEL CONSUMPTION FOR A BOILER IS MISSING                748          BP

LEGEND OF ACTIONS TAKEN
***********************
      NA - NO ACTION TAKEN
      BP - BYPASS FOR COST ANALYSIS
      SB - SUBSTITUTE STANDARD VALUES


NOTE : THE DATA VALIDITY CODE EXPLANATIONS GIVEN IN THIS SUMMARY ARE THE SAME AS THOSE
****   APPEARING ON INDIVIDUAL PLANT & COST ANALYSIS REPORTS
```

TABLE 4.3

UPGRADED UTILITY DATA BASE

```
         STATE :                          COUNTY :                                                              STATE CODE :   1
         *****                            ******                                                               COUNTY CODE :  97
         UTILITY NAME:                     PLANT NAME ADDRESS.                                                   AQCR CODE :   5
         ************                      ******************                                          LOCATION FACTOR : 0.0
         FPC UTILITY CODE:                                          FPC PLANT CODE:                    ****************
         ****************                                           **************
 -------------------------------------------------------------------------------------------------------------------------------
 I  PLANT DATA SUMMARY                                                    NUMBER OF BOILERS:  5                                  I
 I  ******************                                                    *****************                                      I
 I ANNUAL FUEL CONSUMPTION   PLANT SIZE(MW)=1770.80 HEATING VALUE OF:                                                            I
 I COAL(MTONS/YR) = 2321.50 % SULFUR IN COAL= 2.61   COAL (BTU/LB)  = 12008.00                                                   I
 I  OIL (MBBL/YR) =  159.90 % SULFUR IN OIL = 0.50    OIL (BTU/LB)  =136000.00                                                   I
 I  GAS (MCF/YR)  =     0.0                           GAS (BTU/CF)  =      0.0                                                   I
 -------------------------------------------------------------------------------------------------------------------------------
 I  BOILER DATA SUMMARY                                                                                                          I
 I  *******************                      AMT OF S      HRS.                                         DESULFURIZATION          I
 I BOILER  BOILER   FUEL CONSUMED             EMITTED       OF   CAPACITY     FLUE GAS FLOW RATE        EQUIPMENT OPG.           I
 I NUMBER  SIZE    COAL    OIL     GAS      CALC.  REPORT  OPN.   FACTOR              LOAD                   DATA                I
 I         (MW)   MT/YR MBBL/YR   MMCF        (MT/YR)                %      100%      75%        50%     EFF   HRS OF            I
 I                                                                                   ACFM                 %    SERVICE           I
 I   1     153.1   325.     4.       0.   8.503  8.306  7403     63.00       0.        0.         0.      0.0       0            I
 I   2     153.1   299.    10.       0.   7.895  7.662  7753     56.00  716000.   440000.    294000.      0.0       0            I
 I   3     272.0   522.    15.       0.  13.745 13.360  7432     57.00  639000.   462000.    325000.      0.0       0            I
 I   4     403.8   680.    26.       0.  17.970 17.423  6882     52.00  826000.   579000.    394000.      0.0       0            I
 I   5     788.8   312.    35.       0.   8.430  8.007  1402     13.00 1800000.  1400000.   1000000.      0.0       0            I
 -------------------------------------------------------------------------------------------------------------------------------
```

TABLE 4.4

UPGRADED UTILITY DATA BASE (VALIDATED)

Reproduced from best available copy.

```
                                                                                                          STATE CODE :   1
 STATE :ALABAMA                    COUNTY :MOBILE                                                         COUNTY CODE :  97
 *****                             ******                                                                  AQCR CODE :    5
 UTILITY NAME: ALABAMA POWER CO, PLANT NAME ADDRESS:CHICKASAW     MOBILE      36611      LOCATION FACTOR : 1.20
 ************                      ******************                                    ****************
 FPC UTILITY CODE:[illegible]   EPA UTILITY CODE:        FPC PLANT CODE:[illegible]    EPA PLANT CODE:
 ****************               ****************         ***************               ***************

 PLANT DATA VALIDITY CODE * = 0
-------------------------------------------------------------------------------------------------------------------------
I   PLANT DATA SUMMARY                                                              NUMBER OF BOILERS:  4              I
I   ********************                                                            *******************                I
I ANNUAL FUEL CONSUMPTION    PLANT SIZE(MW)= 138.00 HEATING VALUE OF:                                                  I
I COAL(MTONS/YR) =  121.60 % SULFUR IN COAL= 2.13    COAL (BTU/LB)  = 12047.00                                         I
I  OIL (MBBL/YR) =    1.70 % SULFUR IN OIL = 0.50     OIL (BTU/GAL) =138000.00                                         I
I  GAS (MMCF/YR) = 5500.00                            GAS (BTU/CF)  =  1053.00                                         I
-------------------------------------------------------------------------------------------------------------------------
I  BOILER DATA SUMMARY                                                                                                 I
I  **********************                    AMT OF S      HRS.                                      DESULFURIZATION    I
I BOILER   BOILER   FUEL CONSUMED            EMITTED       OF    CAPACITY     FLUE GAS FLOW RATE     EQUIPMENT OPS.    I
I NUMBER   SIZE     COAL    OIL     GAS     CALC.  REPORT OPN.   FACTOR             LOAD                   DATA     DATA I
I          (MW)    MT/YR  MBBL/YR  MMCF      (MT/YR)              %        100%    75%      50%      EFF  HRS OF  VALIDITY I
I                                                                                   ACFM               %   SERVICE CODE * I
I                                                                                                                      I
I   1      46.0     42.      1.   1720.  0.893  0.840  7509   55.00  170000.  162000.  154000.     0.0      0     0    I
I   2      46.0     40.      1.   1680.  0.898  0.827  7282   58.00  170000.  162000.  154000.     0.0      0     0    I
I   4      46.0     40.      1.   2092.  0.859  0.839  7706   58.00  182000.  180000.  178000.     0.0      0     0    I
-------------------------------------------------------------------------------------------------------------------------

 * FOR EXPLANATION OF THIS CODE REFER TO SUMMARY OF ERRORS
```

TABLE 4.5

UPGRADED INDUSTRIAL BOILER DATA BASE

```
        *** INDUSTRIAL  BOILERS  DATA  EXTRACTION  SUBSYSTEM  FROM  NEDS  INPUT  DATA  BASE  ***
                              ENVIRONMENTAL  PROTECTION  AGENCY
                              *********************************
   STATE CODE:     1                COUNTY CODE:  540             AQCR CODE:   2     UTM ZONE: 16               YEAR: 76
   PLANT NO:     1  PLANT NAME:                                            PLANT ID:                    PLANT ERROR CODE:  6
---------------------------------------------------------------------------------------------------------------------------
I  PLANT DATA SUMMARY        PLANT SIZE:        203 MMBTU/HR     NO.BOILERS:  3    TOTAL FUEL BURNT:       1857730 MMBTU/YR   I
I  ******************                                                                                                         I
I  FUEL DATA:  FUEL TYPE        AMOUNT BURNT                HEATING VALUE             PERCENT SULFUR                          I

I               * COAL                0 MMBTU/YR                0 MMBTU/T               0.0                                    I
I               * OIL            116760 MMBTU/YR              140 MMBTU/KG              0.20                                   I
I               * GAS                 0 MMBTU/YR                0 MMBTU/MMCF                                                   I
I               * COKE                0 MMBTU/YR                0 MMBTU/T                                                      I
I               * WOOD          1740970 MMBTU/YR               10 MMBTU/T               0.0                                    I
I               * LPG                 0 MMBTU/YR                0 MMBTU/KG                                                     I
I               * BAGASSE             0 MMBTU/YR                0 MMBTU/T                                                      I
I               * UNCLASS             0 MMBTU/YR                0 MMBTU/T                                                      I

---------------------------------------------------------------------------------------------------------------------------
I  BOILER DATA SUMMARY                                                                                                        I
I  *******************                                                                                                        I

I     BOILER     POINT     SIC     IPP     FLOW R.      TEMP.      BOILER       BOILER     SO2 EMISSIONS  (T/YR)    BOILER     I
I     NUMBER      ID                        ACFM          F         SIZE         LOAD     CALCULATED   REPORTED    ERROR      I
I                                                                 MMBTU/HR                                         CODE      I
I       1          1       2421     0       41953       550          63          1.06          7          100        6       I
I       2          2       2421     0       41953       550          63          1.06          7          100        6       I
I       3          3       2421     0           0         0          77          1.02          0          103        3       I
```

TABLE 4.6

```
*** EPA INDUSTRIAL BOILERS STACK GAS SCRUBBING DATA EXTRACTION SUBSYSTEM ***
         SUMMARY OF ERRORS RELATED TO THE NEDS INPUT DATA FILE
     ************************************************************************

ERROR
TYPE/NUMBER                ERROR DESCRIPTION                                                    NUMBER OF
                                                                                                 ERRORS
-----------------------------------------------------------------------------------------------

PLANT ERRORS
------------

        1     PLANT HAS NO MAJOR ERRORS                                                          3971
        2     % SULFUR FOR COAL MISSING                                                            14
        3     % SULFUR FOR OIL MISSING                                                             47
        4     % SULFUR FOR COKE MISSING                                                             0
        5     AVERAGE HEATING VALUE OF FUEL IS NOT GIVEN                                            0
        6     PLANT USES OTHER FUEL THAN COAL OIL OR GAS                                          519
        7     PLANT CAPACITY ADDS UP TO ZERO                                                      711
        8     PLANT HAS ZERO NUMBER OF BOILERS REPORTED                                             0
        9     ANNUAL TOTAL FUEL CONSUMPTION FOR A PLANT IS NOT GIVEN                              365

BOILER ERRORS
-------------

        1     BOILER HAS NO MAJOR ERRORS REPORTED                                                4562
        2     BOILER FUEL OPERATING RATE IS NOT GIVEN                                             104
        3     BOILER FLOW RATE IS NOT GIVEN                                                      4134
        4     BOILER USES NON STANDARD FUEL                                                       356
        5     BOILER SIZE IS NOT GIVEN                                                           1574
        6     SULFUR EMISSIONS CALCULATED AND REPORTED ARE NOT IN TOLERANCE                      1337
        7     THERE ARE MORE THAN ONE TWO-CARDS PER BOILER                                          0
```

TABLE 4.7

UPGRADED INDUSTRIAL BOILER DATA BASE (VALIDATED)

```
                   ***  INDUSTRIAL  BOILERS  DATA  EXTRACTION  SUBSYSTEM  FROM  NEDS  INPUT  DATA  BASE  ***
                                         ENVIRONMENTAL  PROTECTION  AGENCY
                                         *********************************
   STATE CODE:    1                   COUNTY CODE:  540                AQCR CODE:   2     UTM ZONE: 16            YEAR: 72
   PLANT NO:  1    PLANT NAME:                                                  PLANT ID:                  PLANT ERROR CODE:  6
 I                                                                                                     PLANT VALIDATION CODE:  6     I
 ---------------------------------------------------------------------------------------------------------------------------------------
 I  PLANT DATA SUMMARY        PLANT SIZE:        203 MMBTU/HR     NO.BOILERS:  3     TOTAL FUEL BURNT:        1857730 MMBTU/YR       I
 I  ******************                                                                                                                  I
 I  FUEL DATA:  FUEL TYPE         AMOUNT BURNT                 HEATING VALUE              PERCENT SULFUR                               I
 I                * COAL                                          0 MMBTU/T                  0.0                                       I
 I                * OIL                                         140 MMBTU/MG                 0.20                                      I
 I                * GAS                                           0 MMBTU/MMCF                                                         I
 I                * COKE                                          0 MMBTU/T                  0.0                                       I
 I                * WOOD                                         10 MMBTU/T                                                            I
 I                * LPG                                           0 MMBTU/MG                                                           I
 I                * BAGASSE                                       0 MMBTU/T                                                            I
 ---------------------------------------------------------------------------------------------------------------------------------------
 I  BOILER DATA SUMMARY                                                                                                                 I
 I  *******************                                                                                                                 I
 I      BOILER     POINT     SIC      IPP      FLOW R.      TEMP.       BOILER    BOILER     SO2 EMISSIONS(T/YR)        BOILER    BOILER I
 I      NUMBER      ID                          ACFM          F          SIZE      LOAD     CALCULATED  REPORTED        ERROR     VALID. I
 I                                                                     MMBTU/HR                                        CODE      CODE  I
 I        1          1       2421      0        22050        550         63        1.06          7         100            6         6   I
 I        2          2       2421      0        22050        550         63        1.06          7         100            6         6   I
 I        3          3       2421      0        26950          0         77        1.02          0         103            3         4   I
 REFER TO THE SUMARY AT THE END FOR ERROR CODE EXPLANATION
```

TABLE [illegible]

```
*** EPA STACK GAS SCRUBBING DATA VALIDATION SUBSYSTEM FOR INDUSTRIAL BOILERS ***
           SUMMARY OF ERRORS & EDITS MADE TO UPGRADED DATA BASE
           ****************************************************

    DATA                     EXPLANATION OF DATA VALIDITY CODE                       NUMBER OF    [illegible]
VALIDITY CODE                                                                                     [illegible]
                                                                                      PLANTS
                                                                                      ******
     [illegible]     NO EDITING IS REQUIRED                                          3844        [illegible]
     4               HEATING VALUE IS MISSING                                        [illegible]  5[illegible]
     5               PLANT USES OTHER FUELS THAN [illegible] [illegible] GAS         [illegible]  [illegible]
     7               PLANT CAPACITY [illegible] [illegible]                          [illegible]  [illegible]
     8               PLANT HAS ZERO NUMBER OF BOILERS REPORTED                       [illegible]  [illegible]
     9               ANNUAL FUEL CONSUMPTION FOR [illegible] PLANT IS NOT GIVEN      375         [illegible]
     10              PLANT TO BYPASS WITH MAJOR ERRORS                               1141        [illegible]

                                                                                      BOILERS
                                                                                      *******
     1               NO EDITING IS REQUIRED                                          [illegible]  [illegible]
     2               BOILER LOAD IS ZERO AND REPLACED BY .5                          2514        5[illegible]
     3               BOILER LOAD IS GREATER THAN [illegible] AND REPLACED BY .5      954         5[illegible]
     4               GAS FLOW RATE IS MISSING                                        5113        5[illegible]
     5               BOILER SIZE IS NOT GIVEN                                                    [illegible]
     6               SO2 EMISSIONS CALCULATED [illegible] [illegible] TOLERANCE      1337        [illegible]

  LEGEND:            0=NO ACTION TAKEN
                     4=BYPASS
                     5=SUBSTITUTE
```

FIGURE 4.1

TAIL GAS FLOW RATES FROM EXISTING SULFURIC ACID PLANTS

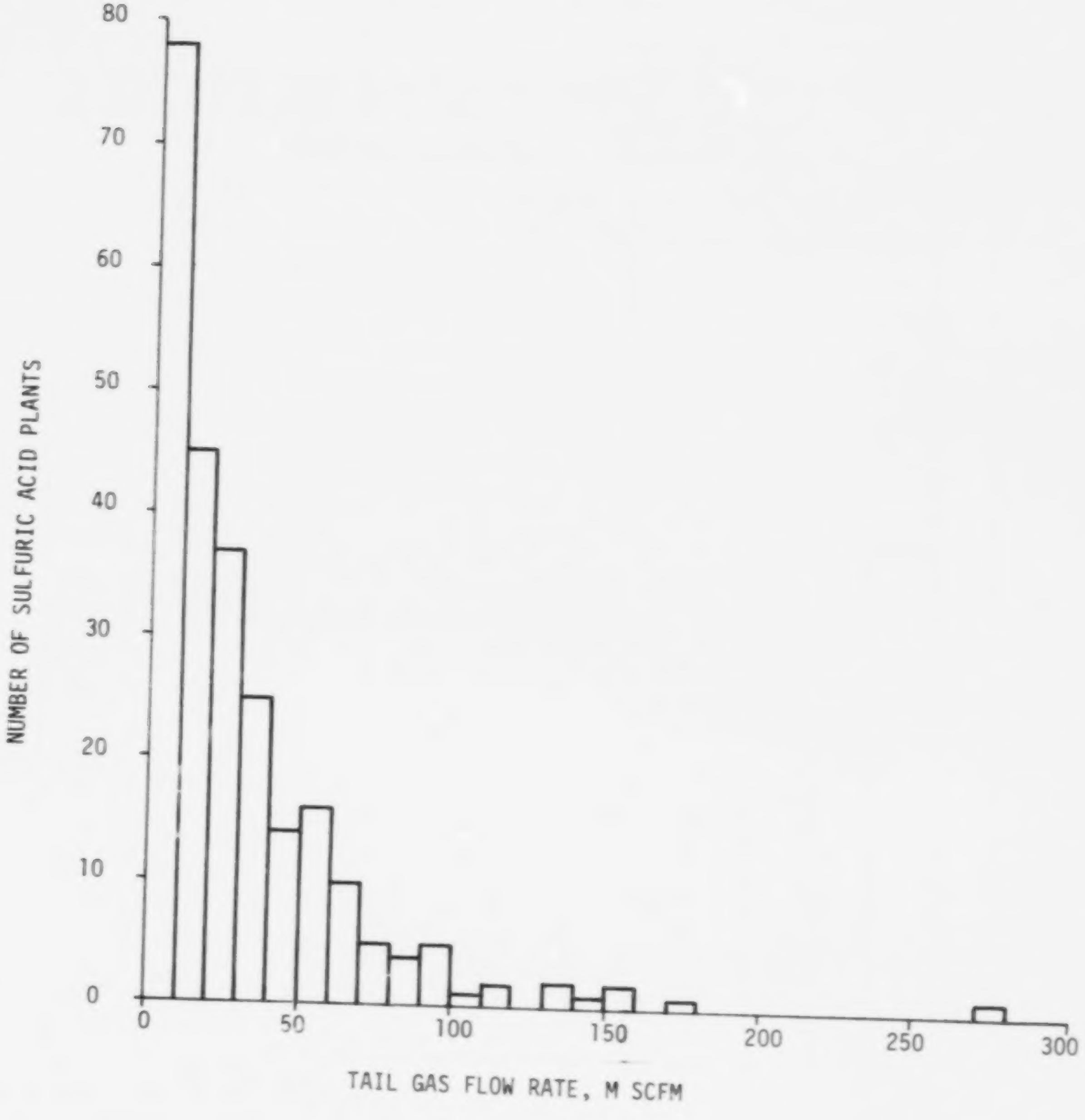


FIGURE 4.2

SULFUR DIOXIDE EMISSIONS FROM EXISTING SULFURIC ACID PLANTS

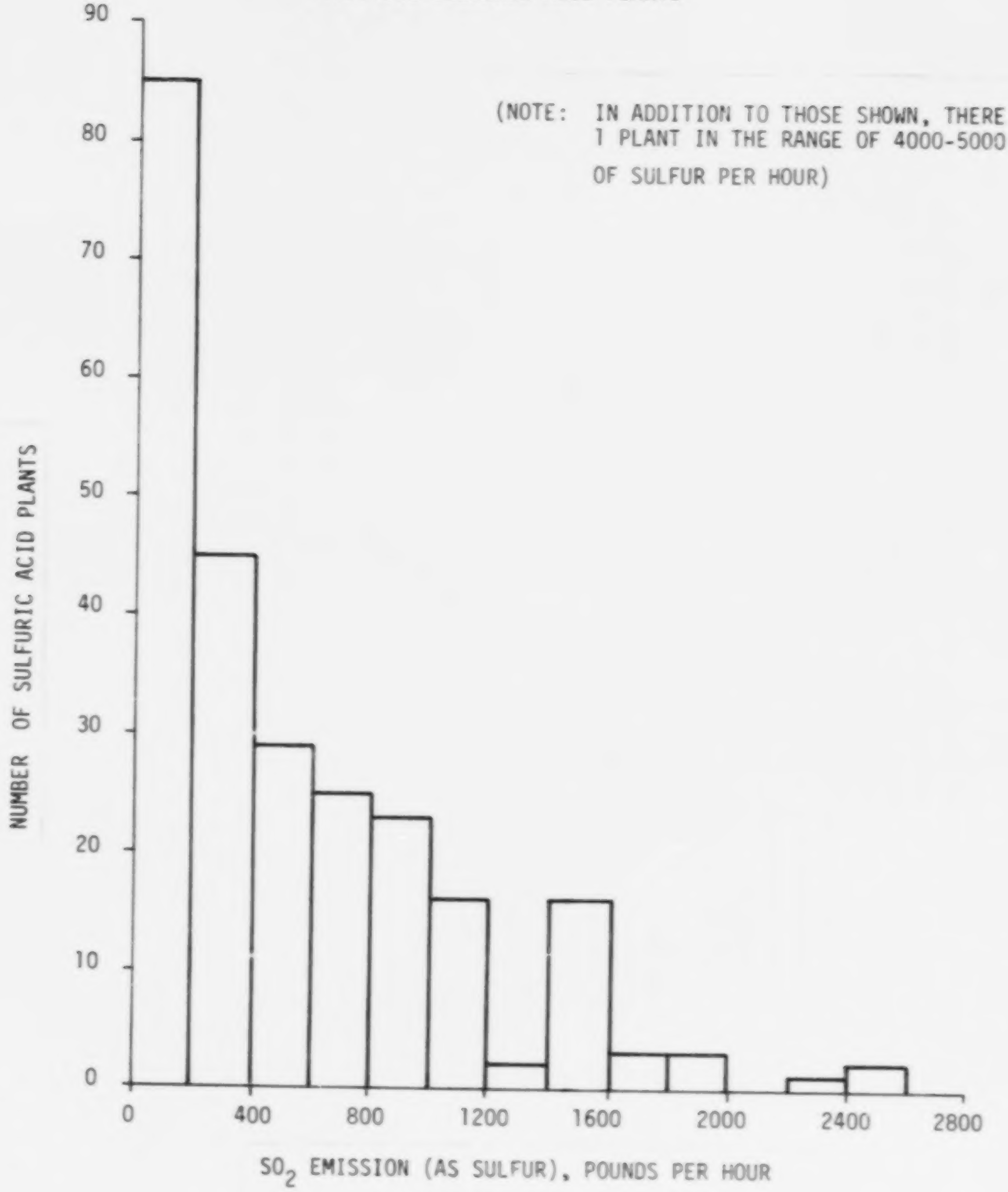


FIGURE 4.3

ACID MIST EMISSIONS FROM EXISTING SULFURIC ACID PLANTS

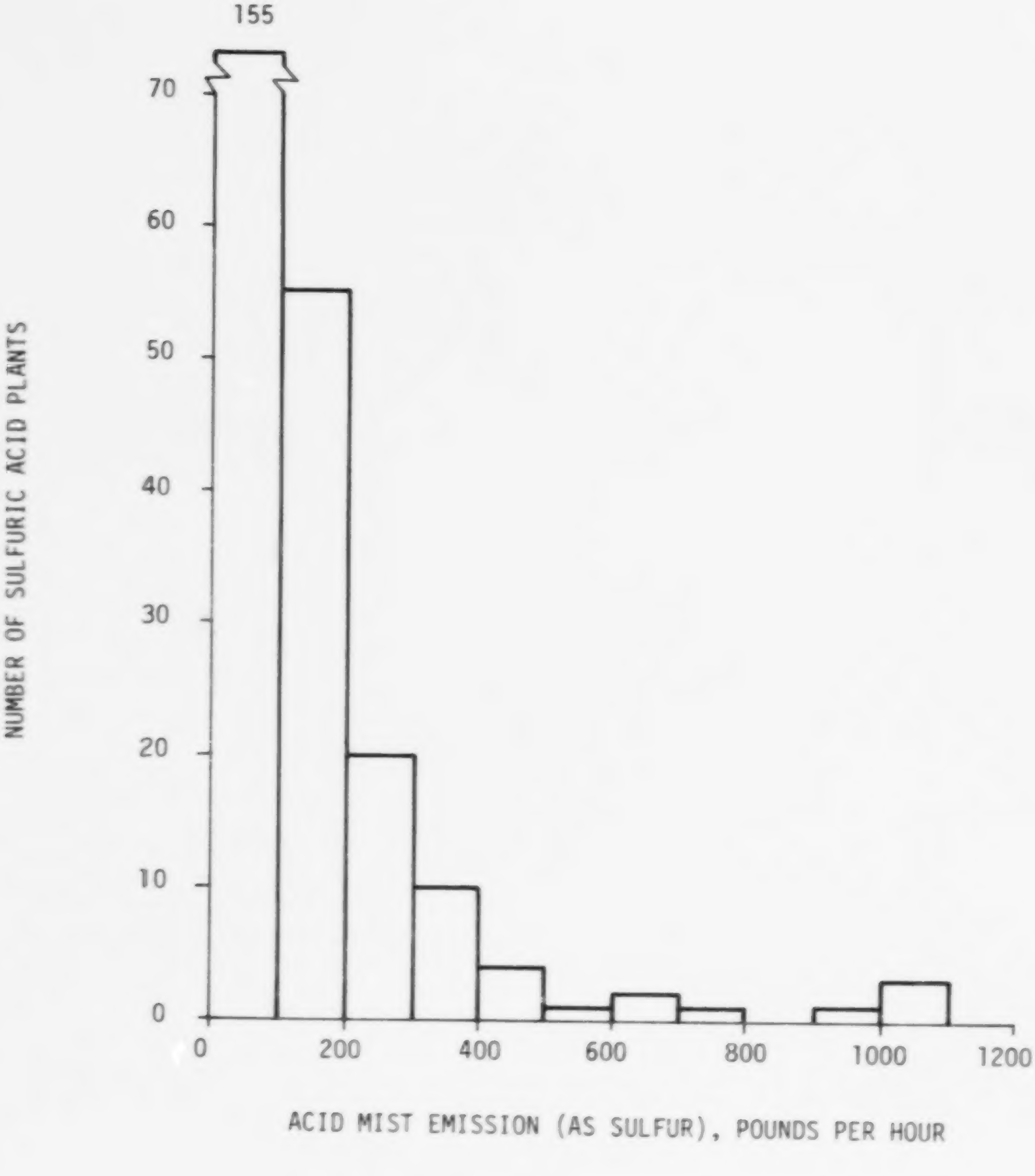
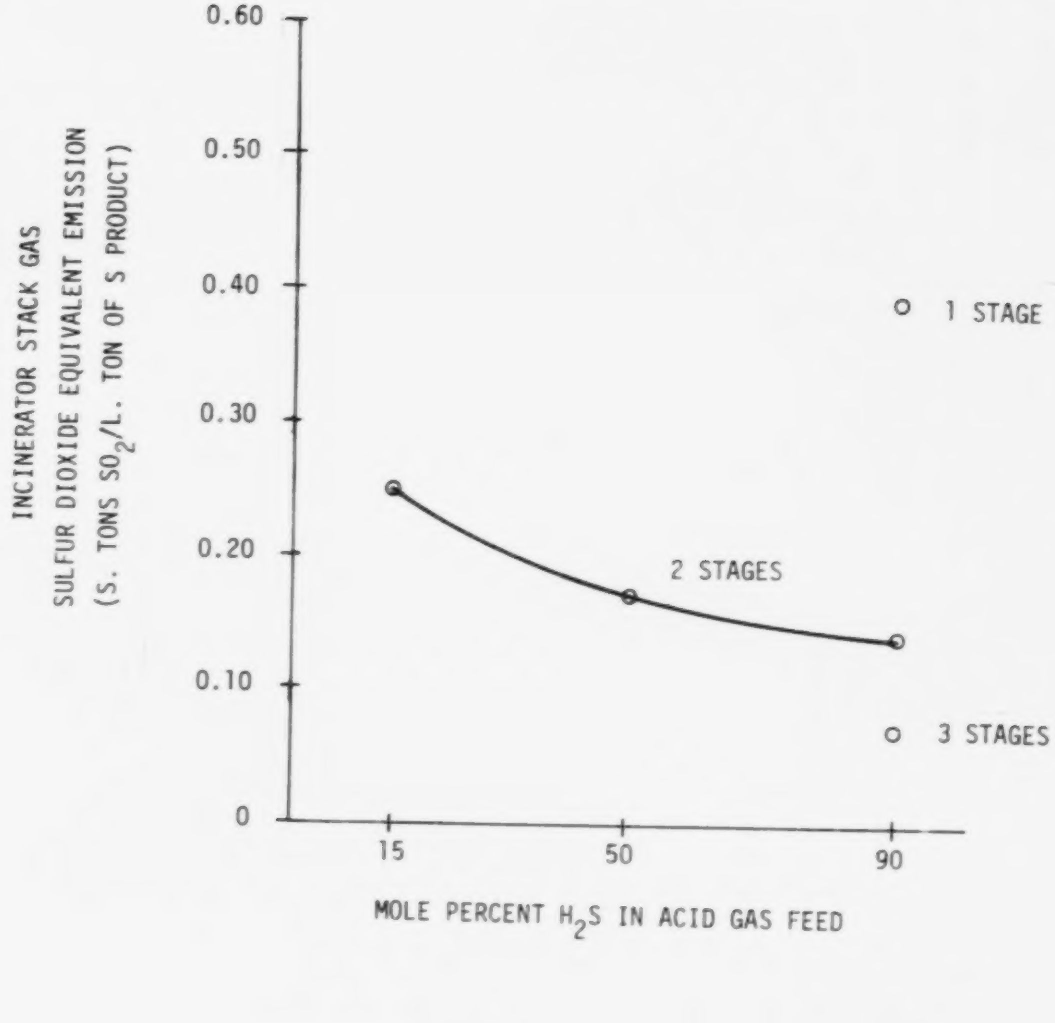


FIGURE 4.4
CLAUS PLANT EMISSIONS



5. THE GENERAL COST MODEL

5.1 Introduction

In Part 1 of this study, a general cost model was developed to provide a standard format for estimating process economics. The purpose was to allow economic comparisons between processes to be made on a consistent basis by ensuring that all estimates include the same cost items.

The general cost model developed in Part 1 of this study uses a utility-type financing method and is based on a procedure recommended in the literature (20). Fundamentally, the model assumes no time value for money. That is, for estimating the economics of desulfurization processes, such items as interest on debt and return on investment can be related to capital costs by simple percentages which remain constant from year to year. This method allows a simple, straight-forward calculation of process operating costs.

For Part 2 of this study, the model was reviewed to determine what changes should be made when applying it to the industrial sector. The revised model differs from the utility financing method primarily in that it uses the discounted cash flow method, which takes into recount the time value of money. It is essentially based on a procedure recommended in the literature (20), with some minor modifications. The revised model has been used for estimating the economics of flue gas desulfurization processes applied to sulfuric acid plants, sulfur (claus) plants, and industrial boilers.

5.2 Review of the Utility Financing Method

The general cost model from Part 1 of this study has been excerpted in its entirety and is included in Appendix C for reference. A brief review will be given here to introduce the reader to the model.

The general cost model consists of two parts: A capital cost model and an operating cost model. The capital cost model is a factored estimate. Where complete cost data are lacking for a particular process, the model allows factoring from equipment costs (E) to total capital required (TCR). Of course, where more complete process cost estimates are available, the model is used merely as a checklist to ensure inclusion of all appropriate cost items. Thus, the model can be "entered" at any level, depending upon the stage of development of process economics. The operating cost model needs, as minimal input, an estimate of process capital costs, operating labor requirements, and consumption of raw materials, utilities, chemicals, catalysts, etc. The total annual production cost (TAC) can then be calculated on the basis of these variables.

If equipment costs (E) for a process are known, or can be estimated, the total capital required (TCR) for construction of the plant can be calculated from the model. Construction labor costs (L) and other material costs (M), such as piping, electical, instrumentation, etc., are estimated as percentages of equipment costs. The model permits variations in construction labor costs with geographical area to be estimated via a location factor (F). Engineering costs are factored from total direct material costs (E+M). The bare cost (BARC) of the plant, defined as the sum of equipment costs, other material costs, construction costs, and engineering, can thus be estimated from equipment costs only. Of course, if the process economics have been developed further than equipment costs, the "factors" derived from the process cost estimate can be substituted for the "typical" factors used in the model.

To the base cost is added taxes and insurance, contractor's overheads and profit, and contingency (CONTIN). Each of these is estimated as a percentage of the base cost, and the sum of all items represents the total plant investment (TPI). In order to obtain the total capital required (TCR), start-up costs (STC), working capital (WKC), and interest during construction (IDC) are added to the total plant investment. The first two items are estimated as a function of process operating costs, and can simply be related to the total number of operators (TO), the hourly rate for operators (CO), the annual cost of raw materials and utilities less by-product credits (ANR), and the annual credit for by-products (ACRED). Interest during construction is a function of total plant investment, and is also related to the total engineering and construction time.

The operating cost model is similarly constructed. The total net operating cost (AOC) is defined as the sum of annual costs of raw materials and utilities less by-product credits (ANR), operating labor and supervision (AOL), maintenance labor and supervision (AML), plant supplies and replacements (APS), administration and overheads (AOH), and local taxes and insurance (ATI). Raw material and utilities costs, credits, and operating labor requirements are, of course, different for each process and must be known before operating costs can be estimated. The remaining terms can all be expressed as a function of total plant investment or total operating labor costs.

In order to obtain the total annual production cost (TAC), capital charges must be added to the total net operating cost. Depreciation (ACR) is determined using the straight line method over the plant life, based on the total capital required less the working capital. Interest or debt and return on equity (AIC) are calculated by assuming a debt-to-equity ratio, an interest rate (Debt), and a net rate of return (Equity). Federal income taxes (AFT) are determined using an assumed tax rate of 48%. The resultant equation for total annual production cost can be simplified and expressed as a function of only a few variables: total plant investment, operating labor requirements, and raw material and utility costs.

The important equations for the utility financing method of the general cost model are summarized in Table 5.1. For a complete definition of the terms shown in the table, the reader is referred to Appendix J.

5.3 Discounted Cash Flow Method

The discounted cash flow method of the general cost model was developed for industrial applications of control processes, and in this report is used only for stack gas scrubbing economics. It also consists of two parts: a capital cost model and an operating cost model. The essential difference between the discounted cash flow method and the utility financing method is the way in which capital charges are determined.

Through total plant investment (TPI), the capital cost model is constructed as described in the previous section. In order to obtain the total capital required (TCR), working capital (WKC) and return on investment during construction are added to the total plant investment. Working capital is related to operating costs, as before. The term, return on investment during construction, replaces interest during construction used in the utility financing method. This arises from the assumption of a 100% equity position for project financing in the discounted cash flow method. It should be noted that start-up costs are not treated as capitalized costs, and therefore are not included in the total capital required. Start-up costs are assumed to be an initial operating expense.

The total net operating cost (AOC) is calculated in an identical manner to that described in the preceding section. To this must be added the capital charges to yield the total annual production cost (TAC). The following procedures have been used to apply the discounted cash flow method to the general cost model:

1. Net operating costs are determined for each year. Start-up costs are included as an initial operating expense.
2. An accelerated depreciation schedule (Sum-of-the-years digits) is used. Depreciation is taken over the plant life, based on the total plant investment.
3. A federal tax rate of 48% has been assumed.
4. Cash flows are determined for each year of the project life. These values are then discounted, using the desired net rate of return on investment. This yields the discounted cash flows for each year of the project life.
5. A constant yearly production cost is calculated which gives the desired discounted cash flow rate of return on investment over the project life. This cost, then, includes both capital recovery and return on investment.

The important cost equations for the discounted cash flow method are summarized in Table 5.2. The general equation for total annual production cost (TAC) shows it to be a function of the total capital required (TCR), start-up costs (STC), working capital (WKC), total plant invesment (TPI), net annual operating costs (AOC), plant life (l), and the rate of return on investment (r). For stack gas scrubbing units, the equation can be greatly simplified, as shown in the table. A complete derivation of the equations for total annual production cost is given in Appendix D.

TABLE 5.1
GENERAL COST MODEL
SUMMARY OF EQUATIONS
UTILITY FINANCING METHOD

CAPITAL COST MODEL

$\mathrm{BARC} = 1.15\ (E + M) + 1.43\ L \cdot F$

$\mathrm{TPI} = 1.12\ (1.0 + \mathrm{CONTIN})\ \mathrm{BARC}$

$\mathrm{TCR} = \mathrm{TPI} + \mathrm{STC} + \mathrm{WKC} + \mathrm{IDC}$

For stack gas scrubbing units,

$\mathrm{TCR} = 1.15\ \mathrm{TPI} + 1.8\ \mathrm{TO} \cdot \mathrm{CO}\ (1.0 + F) + 0.4\ (\mathrm{ANR} + \mathrm{ACRED})$

For other units,*

$\mathrm{TCR} = 1.21\ \mathrm{TPI} + 0.8\ \mathrm{TO} \cdot \mathrm{CO}\ (1.0 + F) + 0.4\ (\mathrm{ANR} + \mathrm{ACRED})$

OPERATING COST MODEL

$\mathrm{AOC} = \mathrm{ANR} + \mathrm{AOL} + \mathrm{AML} + \mathrm{APS} + \mathrm{AOH} + \mathrm{ATI}$

$= 0.078\ \mathrm{TPI} + 2.0\ \mathrm{TO} \cdot \mathrm{CO}\ (1.0 + F) + \mathrm{ANR}$

$\mathrm{TAC} = \mathrm{AOC} + \mathrm{ACR} + \mathrm{AIC} + \mathrm{AFT}$

For stack gas scrubbing units,

$\mathrm{TAC} = 0.237\ \mathrm{TPI} + 2.1\ \mathrm{TO} \cdot \mathrm{CO}\ (1.0 + F) + 1.04\ \mathrm{ANR} + 0.042\ \mathrm{ACRED}$

For other units,*

$\mathrm{TAC} = 0.225\ \mathrm{TPI} + 2.1\ \mathrm{TO} \cdot \mathrm{CO}\ (1.0 + F) + 1.04\ \mathrm{ANR} + 0.039\ \mathrm{ACRED}$

---

*SNG, SRC, low Btu gas, intermediate Btu gas

TABLE 5.2
GENERAL COST MODEL
SUMMARY OF EQUATIONS
DISCOUNTED CASH FLOW METHOD

CAPITAL COST MODEL

$$\text{BARC} = 1.15\ (\text{E} + \text{M}) + 1.43\ \text{L}\cdot\text{F}$$

$$\text{TPI} = 1.12\ (1.0 + \text{CONTIN})\ \text{BARC}$$

$$\text{TCR} = \text{TPI} + \text{WKC} + \text{IDC}$$

For stack gas scrubbing units,

$$\text{TCR} = 1.15\ \text{TPI} + 0.4\ \text{TO}\cdot\text{CO}\ (1.0 + \text{F}) + 0.20\ (\text{ANR} + \text{ACRED})$$

OPERATING COST MODEL

$$\begin{aligned}\text{AOC} &= \text{ANR} + \text{AOL} + \text{AML} + \text{APS} + \text{AOH} + \text{ATI}\\ &= 0.078\ \text{TPI} + 2.0\ \text{TO}\cdot\text{CO}\ (1.0 + \text{F}) + \text{ANR}\end{aligned}$$

$$\begin{aligned}\text{TAC} = \frac{1}{0.52}\left[\frac{r\ (1+r)^{\ell}}{(1+r)^{\ell}-1}\right]\ &\left[\text{TCR} + \text{STC} - \frac{\text{WKC}}{(1+r)^{\ell}} - 0.48\ \text{TPI} \times \frac{2}{\ell(\ell+1)}\right.\\ &\left.\frac{\ell + 1 - n}{(1 + r)^{n}}\ \right] + \text{AOC}\end{aligned}$$

For stack gas scrubbing units,

$$\begin{aligned}\text{TAC} &= \frac{\text{TCR} + \text{STC} - 0.239\ \text{WKC} - 0.291\ \text{TPI}}{3.955} + \text{AOC}\\ &= 0.298\ \text{TPI} + 2.18\ \text{TO}\cdot\text{CO}\ (1.0 + \text{F}) + 1.09\ \text{ANR} + 0.09\ \text{ACRED}\end{aligned}$$

6. COST OF STACK GAS SCRUBBING

6.1 Utility Plants

6.1.1 Comparision of Cost Analysis as Applied to Different Data Bases

Part 1 of this study investigated the cost of retrofitting stack gas scrubbing units to existing utilities. However, as pointed out in section 4.1.1 of this report the same costs had to be re-estimated and summarized using an upgraded data base. This new data base is smaller but more reliable than the original one. The costs obtained using this data base are much more reliable and realistic. The control strategy applied in both cases is the same, viz., the control is applied to the individual boilers in decreasing order of their sulfur emissions. This means that if a plant is emitting sulfur above the allowable emission level (assumed to be 1.2 lbs of SO_2/MMBtu), then control is applied to the largest sulfur-emitting boiler. If this does not reduce emissions below the allowable level, then the boiler emitting the second largest amount of sulfur is controlled. This scheme is continued until plant emissions are below the allowable level.

In Part 1 of this study, after the data base was edited for missing values and magnitude errors the fuel demand for the boilers was calculated, using the boiler load factor and boiler heat rate. Since only the overall plant fuel consumption was known (by types and amounts), the fuel within a plant had to be allocated to the various boilers. Allocation was done in the order of coal, oil and gas, starting with the largest boiler and working toward the smallest boiler. In most cases the largest boiler became the largest emitter of sulfur. In reality this may not be true. Tables 6.1 and 6.2 give the capital costs and operating costs for an identical plant in the following two cases:

Table 6.1 - Using fuel allocation as described above.
Table 6.2 - Using actual plant data.

Since the stack gas scrubbing costs for each individual plant are different, it can be expected that the costs on a national and state basis will be different using different data bases. For a comparison of any specific cost, the figures should be compared with costs in Part 1 of this study.

6.1.2 Scrubbing Cost Analysis Using Upgraded Data Base

The figures and tables in this section present the results obtained by applying the cost models for the two different scrubbing processes, viz., the wet limestone process and the Wellman/Allied system. The cost models, unit costs for raw materials, location factors, etc. used in this study are identical to those used in Part 1 of this study (The cost models are summarized in Appendix E). The allowable plant emission level has been assumed to be 1.2 lbs. SO_2/MMBtu, consistent with Part 1. Only plants requiring control are included in the cost analysis.

Table 6.3 and Table 6.4 give a breakdown of costs for each state for the two processes. It must be noted that the costs are based on a limited number of plants only. Hence, the entries under columns titled total capacity, total production, total capital required and total operating costs are likely to be under-estimated. These figures are only from the plants requiring controls on at least 1 boiler of the plant. Of the 417 plants considered for cost analysis 256 of them required control on at least 1 boiler. This represents 55% of the plants considered. The variation in operating costs between two identical plants in different states results from different location factors.

Figure 6.1 represents the average total capital required for installing wet limestone and Wellman/Allied stack gas scrubbing units in existing utilities of different sizes. The graph shows that the variation between the costs of the two scrubbing processes is small.

Figure 6.2 represents the relationship between the plant size and the total capital requirement, in $/KW, for the two processes. It can be seen that with an increase in the size of the plant the capital requirement drops. Costs vary from about $40/KW to almost $200/KW for plants in the range of 3000 to 40 MW.

Figure 6.3 illustrates the average annual cost of production (MM$/year) for installing stack gas scrubbing in existing power plants. There is no significant difference in costs between the two processes.

Figure 6.4 shows the relationship of the plant size to the incremental operating cost (mills/KWh). This cost ranges from 4 mills/KWh to 2 mills/KWh for plants between 400 MW to 2000. This graph suggests that for small plants, it would probably be more economical to switch from stack gas scrubbing to burning clean fuel for controlling SO_2 emissions.

Figure 6.5 illustrates how the maximum total capital requirement, in $/KW , for installing stack gas scrubbing varies with the percent of U.S. utility plant capacity under control. 80% of the total plant capacity could be controlled at costs of $100/KW or less. Applying controls to the remaining 20% of plant capacity, which includes essentially the smaller plants, would result in excessively high costs, as much as $700/KW. If only the first 20% of the plant capacity was controlled the capital requirement for stack gas scrubbing is of the magnitude of $40/KW or less.

Figure 6.6 presents the maximum total cost of production, in mills/KWH, for installing stack gas scrubbing as a function of the percent of total plant production controlled. This graph can be interpreted in a similar manner to figure 6.5. It would become increasingly uneconomical to apply stack gas scrubbing as a means of controlling SO_2 emissions to approximately the last 10% total plant production.

Figure 6.7 shows the cumulative total capital requirement, in MM$, versus the % of plant capacity under control. While interpreting this graph, one must be aware that the absolute cost (total capital required) for controlling 10% of the total US power plant capacity is not $700 MM but much higher. This is, as was explained earlier in 4.1, due to only a limited number of plants being included in the data base. However, since the sample does include a large number of plants from all over the US, scaling of absolute cost figures may be reasonable. Figure 6.8 illustrates the relationship between the same quantities except that the basis of cumulating the costs is different for the two graphs. The two graphs show that if stack gas scrubbing was used to control the entire power capacity, the total capital cost would be the same. However, when only a certain percentage, say 50%, of the entire plant capacity is to be controlled, it would be more economical to install stack gas scrubbing on the basis of increasing TCR ($/KW) rather than on the basis of the decreasing plant size.

Figures 6.9 and 6.10 illustrate the relationship between the cumulative total cost of production, in MM$/Yr, and the % of the total plant production controlled. The operating cost is lower for controlling a certain % of the plant production if controls are applied on the basis of increasing operating costs (mills/KWH). For example, to control 60% of the total plant production, the cumulative operating cost is $920 MM/year when controls are applied on the basis of the summation in order of increasing TAC, while the cost for controlling on the basis of decreasing plant production is $1200 MM/year. The total cost figures are based only on the limited number of plants considered.

6.2 Sulfuric Acid Plants

6.2.1 Process Appraisal

Of the two flue gas desulfurization processes investigated in this study, only the regenerable process (Wellman/Allied) has been included for application to sulfuric acid plants. The basis for the process and cost models is the design for the demonstration plant under construction at the D. H. Mitchell plant of the Northern Indiana Public Service company (NIPSCO). This design combines the Wellman-Lord SO_2 recovery process and the Allied Chemical SO_2 reduction process to produce elemental sulfur as an end product.

The model for sulfuric acid plants has been developed following the same procedure used in the report on Part 1 of this study, where the Wellman/Allied process and cost models for utility boilers were developed. A review and evaluation of the NIPSCO design was presented in that report and several process changes were made. While most of these changes were adopted for the present model, additional modifications were introduced because of the difference in the stack gas emissions from sulfuric acid plants and utility boilers.

As discussed in section 4.3, sulfuric acid mist constitutes an important fraction of the total sulfur emission from acid plants. In order to prevent the formation of sulfate in the scrubbing system, sulfuric acid mist has to be removed from the acid plant tail gas before it enters the absorber. The results presented in the report "Engineering Analysis of Emissions Control Technology for Sulfuric Acid Manufacturing Processes" prepared by Chemico (4) have been used to determine the most effective method for acid mist removal. It was found that electrostatic precipitators and fiber mist eliminators are the only devices capable of reducing the acid mist concentration to less than the EPA New Source Performance Standard of 0.15 pounds per ton of acid. Of these two alternatives, fiber mist eliminators represent a lower investment and were therefore adopted for the design.

Acid mist eliminators become more expensive as their efficiency is improved. On the other hand, the formation of sodium sulfate is increased by the amount of acid mist that goes into the absorber. This in turn increases the make-up chemical cost and the cost of purge treatment. Therefore, it is important to point out that studies should be made in order to determine an economically optimum balance between the amount of acid mist that is removed in the eliminator and in the absorber. However, this would require additional information on acid mist particle size distributions and studies of acid mist removal in the absorber.

In the absence of this information, a high efficiency type mist eliminator was incorporated into the model in order to make it applicable to all acid plants. This type of design will collect particles greater than 3 microns in size with essentially 100% efficiency and all remaining particles with 99.5% efficiency. The recovered sulfuric acid can then be returned to the acid plant.

The tail gas discharge from acid plants does not contain any fly ash. In view of this fact, all equipment related to fly ash removal has been either modified or eliminated from the design. The prescrubbing section of the absorber tower has been reduced and modified to serve the only purpose of saturating the incoming gas with water vapor. The absorber surge tank and fly ash filter system were eliminated while the evaporator feed tank was enlarged to provide enough surge capacity.

The Allied process for sulfur recovery has not been included in the model since the recovered sulfur dioxide can be directly recycled to the converter in the acid plant.

In accordance with the model for utility boilers, the absorber was designed for an overall SO_2 removal efficiency of 95% and all the pieces of equipment have been sized for 100% load factor.

6.2.2 Variation of Equipment Costs and Plant Size

The flue gas discharge from utility boilers is much greater than that from sulfuric acid plants, i.e., at full capacity, the largest acid plant discharges 288 M SCFM of tail gas, comparable to the flow from an 80 megawatt utility boiler. In order to avoid large extrapolations from the reference size plant used in the previous model, it was necessary to investigate and determine cost correlations for small size equipment. As a result of this study, the exponents relating cost to size for different types of equipment are generally different from those used in the model for utility boilers.

	Cost proportional to
Tower shells (including lining)	$(ACFM)^{0.6}$
Tower internals	$(ACFM)^{0.9}$
Centrifugal pumps	$(BHP)^{0.1 - 0.5}$
Tanks and drums	$(volume)^{0.5}$

	Cost proportional to
Agitators	$(BHP)^{0.5}$
Fans, blowers, and compressors	$(BHP)^{0.8 - 0.9}$
Direct fired heater	$(duty)^{0.5}$
Ductwork and dampers	$(ACFM)^{0.9}$
Heat exchangers	$(surface)^{0.4 - 0.5}$
Forced circulation evaporators (complete system)	$(duty)^{0.7}$
Storage silos and bins	$(volume)^{0.8}$
Pressure vessels	$(volume)^{0.5}$
Pressure vessel internals	$(ACFM)^{0.9}$
Miscellaneous solids handling equipment	$(flow)^{0.8}$
Mist eliminator (elements)	$(ACFM)^{1.0}$

Equipment sizes for the process were related to one of three basic variables: the tail gas flow, the flow of sulfur as SO_2 in the tail gas, and the flow of sulfur as acid mist in the tail gas. The mist eliminator system, absorber, and related equipment are proportional in size to the tail gas flow. The pumps that return the recovered sulfuric acid to the acid plant are proportional in size to the flow of sulfur from acid mist in the flue gas. The remainder of the process equipment in the plant is proportional to the flow of sulfur from SO_2 in the tail gas.

The process is divided into three main areas:

1) The absorber area, including the mist eliminator system, gas reheat, and compression.
2) The SO_2 regeneration area.
3) The purge/make-up area.

An analysis of the different areas showed that, for sulfuric acid plants, it was not necessary to use multiple trains since the plant capacities involved are well below the maximum train sizes determined in the model for utility boilers.

A reference plant size to be used in the model was chosen to handle a tail gas flow of 20,000 ACFM (@170°F, 14.7 psia), a sulfur rate (as SO_2) of 350 pounds per hour (lbs/hr), and a sulfur rate (as acid mist) of 50 lbs/hr. These figures were obtained by averaging the highest and lowest emissions from existing acid plants in order to make the scale-up and scale-down factors comparable in magnitude.

The following factors were determined in order to scale-down from the adjusted NIPSCO design to the reference plant size:

	Scale-down factor
For the gas flow	0.0536
For the sulfur (from SO_2) rate	0.1452

6.2.3 Cost Model

1. Equipment Costs

Equipment costs have been calculated for the different areas of the reference plant and are as follows:

1) The Absorber Area

		Cost of Reference Size Train M$ (end of 73)	Cost Relationship
a)	Mist eliminator elements	32.5	$GP^{1.0}$
b)	Mist eliminator tank	18.6	$GP^{0.5}$
c)	Sulfuric acid pumps	1.1	$SM^{0.1}$
d)	Absorber shell and lining	41.4	$GP^{0.6}$
e)	Absorber internals	22.7	$GP^{0.9}$
f)	Prescrubber circulation pumps, quench pumps, and absorber circulation pumps	8.3	$GP^{0.4}$
g)	Induction Fan	12.6	$GP^{0.9}$
h)	Reheater, ductwork, dampers	35.4	$GP^{0.8}$
i)	Fuel oil system	25.8	$GP^{0.5}$
j)	Evaporator feed tank, agitator, and pumps	15.1	$S^{0.5}$
	Total equipment cost for absorber area, EA =	213.5 M $	

In general, for a plant with a total gas flow of GP M ACFM, a sulfur rate from SO_2 of S lbs/hr, and a sulfur rate from acid mist of SM lbs/hr, the total equipment cost for the absorber area is:

$$
\begin{aligned}
EA = {} & 8.3\left(\frac{GP}{20}\right)^{0.4} + 44.4\left(\frac{GP}{20}\right)^{0.5} + 41.4\left(\frac{GP}{20}\right)^{0.6} \\
& + 35.4\left(\frac{GP}{20}\right)^{0.8} + 35.3\left(\frac{GP}{20}\right)^{0.9} + 32.5\left(\frac{GP}{20}\right) \\
& + 15.1\left(\frac{S}{350}\right)^{0.5} + 1.1\left(\frac{SM}{50}\right)^{0.1} \qquad \text{M \$}
\end{aligned}
$$

Note that the last term is insignificant and can therefore be neglected.

2) The SO_2 Regeneration Area

		Cost of Reference Size Train M$ (end of 73)	Cost Relationship
a)	Tanks, agitators, and heat exchangers	55.1	$S^{0.5}$
b)	Pumps	3.9	$S^{0.3}$
c)	Condensate stripper shell and evaporator system	62.6	$S^{0.7}$
d)	Compressor and condensate stripper internals	10.8	$S^{0.8}$
	Total equipment cost for the SO_2 regeneration area, ES =	132.4	M $

In general, for a plant handling a sulfur (from SO_2) rate of S lbs/hr, the total equipment cost for the SO_2 regeneration area is:

$$ES = 3.9\left(\frac{S}{350}\right)^{0.3} + 55.1\left(\frac{S}{350}\right)^{0.5} + 62.6\left(\frac{S}{350}\right)^{0.7} + 10.8\left(\frac{S}{350}\right)^{0.8} \quad \text{M \$}$$

3) The Purge/Make-up Area

		Cost of Reference Size Train, M $ (end of 73)	Cost Relationship
a)	Pumps and fans	14.5	$S^{0.3}$
b)	Tanks and agitators	14.6	$S^{0.5}$
c)	Plate exchangers and dryer	42.3	$S^{0.4}$
d)	Crystallizer centrifuge, evaporation system, and refrigeration unit	36.6	$S^{0.7}$

e) Bins and miscellaneous solids handling equipment 10.9 $S^{0.8}$

Total equipment cost for the purge/make-up area, EP = 118.9 M $

In general, for a plant handling a sulfur (from SO_2) rate of S lbs/hr, the total equipment cost for the purge/make-up area is:

$$EP = 14.5\left(\frac{S}{350}\right)^{0.3} + 42.3\left(\frac{S}{350}\right)^{0.4} + 14.6\left(\frac{S}{350}\right)^{0.5} + 36.6\left(\frac{S}{350}\right)^{0.7} + 10.9\left(\frac{S}{350}\right)^{0.8} \quad \text{M \$}$$

4) Retrofit Factor

A retrofit factor, RF, has to be introduced to reflect the difficulty of installation and increased costs of gas related equipment for a retrofit installation. This factor will not apply to other areas since these are assumed to be locatable anywhere on the plant site. In the absence of detailed information on sulfuric acid plant lay-outs, this factor has been assumed to be equal to the higher retrofit factors used in the model for utility boilers. This assumption arises from the small plant capacities and older installations.

The total equipment costs for the Wellman-lord system can then be summarized as follows:

$$EA = RF\left[8.3\left(\frac{GP}{20}\right)^{0.4} + 44.4\left(\frac{GP}{20}\right)^{0.5} + 41.4\left(\frac{GP}{20}\right)^{0.6} + 35.4\left(\frac{GP}{20}\right)^{0.8} + 35.3\left(\frac{GP}{20}\right)^{0.9} + 32.5\left(\frac{GP}{20}\right)\right] + 15.1\left(\frac{S}{350}\right)^{0.5} \quad \text{M \$}$$

$$ES = 3.9\left(\frac{S}{350}\right)^{0.3} + 55.1\left(\frac{S}{350}\right)^{0.5} + 62.6\left(\frac{S}{350}\right)^{0.7} + 10.8\left(\frac{S}{350}\right)^{0.8} \quad \text{M \$}$$

$$EP = 14.5\left(\frac{S}{350}\right)^{0.3} + 42.3\left(\frac{S}{350}\right)^{0.4} + 14.6\left(\frac{S}{350}\right)^{0.5} + 36.6\left(\frac{S}{350}\right)^{0.7} + 10.9\left(\frac{S}{350}\right)^{0.8} \quad \text{M \$}$$

2. Other Material Cost and Labor Costs

The same factors used in the cost model for utility boilers have been used to relate the costs of labor and other materials to the major equipment costs. These relations are shown below, where E represents the major equipment cost, L the labor cost, and M the cost of other materials. The subscripts A, S, and P refer to the absorber area, the SO_2 regeneration area, and the purge/make-up area respectively. Labor costs are based on the Gulf Coast area. Field materials include only piping, instruments, electrical, insulation, painting, concrete, and structural steel.

$L_A = 0.224\ E_A$ $\qquad M_A = 0.429\ E_A$

$L_S = 0.310\ E_S$ $\qquad M_S = 0.742\ E_S$

$L_P = 0.623\ E_P$ $\qquad M_P = 0.827\ E_P$

3. Raw Materials and Utilities Costs

1) Sodium Carbonate

The amount of sodium carbonate used to replenish the sodium values lost by oxidation of the scrubbing solution is directly proportional to the sulfur (from SO_2) rate, S. The consumption of sodium carbonate can be scaled directly from the NIPSCO design where 0.265 tons/hr are required. Since the scale-down factor on the sulfur rate is 0.1452, the sodium carbonate make-up for the reference plant at 100% load factor is:

$$\text{Consumption} = \frac{0.265}{1000} \times 0.1452 \times 8760 = 0.337 \text{ M tons/yr}$$

In general, the annual cost of sodium carbonate, AS, for a sulfuric acid plant having a load factor of LF is:

$$AS = 0.337\left(\frac{S}{350}\right) \cdot CS \cdot LF$$

where CS is the purchase price of sodium carbonate in $/ton

2) Power

The power consumption shown for the NIPSCO design has been adjusted to reflect the process and equipment changes described in Part 1. The adjusted power requirement for the NIPSCO design is 3134 KW of which 2467 KW are proportional to the gas flow rate and 667 KW are proportional to the sulfur rate (from SO_2).

The annual power consumption of the reference plant at 100% load factor is:

$$\begin{aligned}\text{Consumption} &= 2.467 \times 0.0536 \times 8760 \text{ (proportional to GP)} \\ &+ 0.667 \times 0.1452 \times 8760 \text{ (proportional to S)} \\ &= 1.160 \text{ M KWH/yr} + 850 \text{ KWH/yr}\end{aligned}$$

The annual power cost, AE, is:

$$AE = \left[1.16\left(\frac{GP}{20}\right) + 0.85\left(\frac{S}{350}\right)\right] CE \cdot LF \qquad \text{M \$/yr}$$

where CE is the purchase (or transfer) price of electricity in mills/KWH.

3) Steam

The steam consumption for the adjusted NIPSCO design is 52.7 M lbs/hr and is proportional to the sulfur rate. For the reference plant at 100% load factor, the steam consumption is:

$$\text{Consumption} = \frac{52.7}{1000} \times 0.1452 \times 8760 = 67 \text{ MM lbs/yr}$$

The annual cost of steam, AH, is:

$$AH = 67\left(\frac{S}{350}\right) CH \cdot LF \qquad \text{M \$/yr}$$

where CH is the purchase (or transfer) price of steam in $/Mlbs.

4) Cooling Water

The total cooling water requirement for the modified NIPSCO design is 3.3 M GPM, of which 0.19 M GPM is proportional to the gas flow and 3.11 M GPM is proportional to the sulfur rate. Cooling water required for the reference plant at 100% load factor is:

$$\begin{aligned} \text{Consumption} &= 0.19 \times 0.0536 \times 60 \times 8760 \text{ (proportional to GP)} \\ &+ 3.11 \times 0.1452 \times 60 \times 8760 \text{ (proportional to S)} \\ &= 5350 \text{ M gal/yr} + 237000 \text{ M gal/yr} \end{aligned}$$

The annual cost of cooling water, ACW, is:

$$ACW = \left[5.4\left(\frac{GP}{20}\right) + 237\left(\frac{S}{350}\right)\right] CCW \cdot LF \qquad \text{M \$/yr}$$

where CCW is the cost of cooling water in \$/M gal.

5) Process Water

For the NIPSCO design, the use of process water is 10 GPM and is proportional to the sulfur rate. Its consumption for the reference plant at 100% load factor is:

$$\text{Consumption} = \frac{10}{1000} \times 0.1452 \times 60 \times 8760 = 760 \text{ M gal/yr}$$

The annual cost of process water, AW, is:

$$AW = 0.76\left(\frac{S}{350}\right) CW \cdot LF \qquad \text{M \$/yr}$$

where CW is the cost of process water in \$/M gal.

6) Fuel Oil

As described in the model for utility boilers, the NIPSCO design was modified to include direct reheating of the flue gas. The consumption of fuel oil for this purpose was established to be 254,000 MM Btu/yr. For the reference plant at 100% load factor, the fuel oil consumption is:

$$\text{Consumption} = 254{,}000 \times 0.0536 = 13{,}600 \text{ MM Btu/yr}$$

The cost of fuel oil, AF, is:

$$AF = 13.6\left(\frac{GP}{20}\right) CF \cdot LF \qquad \text{M \$/yr}$$

where CF is the purchase price of fuel oil in \$/MM Btu.

7) Credits

The process will produce three materials: sulfuric acid, sulfur dioxide, and a dry purge solids stream consisting of sodium sulfite, sodium sulfate, and sodium thiosulfate. Sulfuric acid and sulfur dioxide would normally be returned to the acid plant and can therefore be listed as credits. The purge material may have positive or negative value depending upon whether or not it can be sold. If it is not sold, a waste disposal cost would be incurred. The cost treatment of the purge solids can be handled by insertion of a positive or negative unit value in the model.

a) Sulfuric Acid

Sulfuric acid particles are collected in the mist eliminator elements. The liquid drains to the bottom of the tank and can then be recycled to the acid plant or sold directly as a product.

The reference plant has a sulfur flow (from acid mist) of 50 lbs/hr. At 99.6% overall acid mist removal efficiency, the amount of 100% sulfuric acid recovered in one year at 100% load factor is:

$$\text{Production} = 50 \times 0.996 \times \frac{98.08}{32.06} \times \frac{8760}{2000} = 670 \text{ tons/yr}$$

The sulfuric acid credit, ASA, is then given by:

$$ASA = \frac{0.67}{CONC} \left(\frac{SM}{50}\right) VSA \cdot LF \qquad \text{M \$/yr}$$

where VSA is the value of sulfuric acid in $/ton of acid of concentration CONC.

The value of the recovered sulfuric acid depends on its concentration. The average concentration of the acid mist droplets varies with the concentration of the acid being produced in the acid plant. For the concentration range in consideration, the following linear correlation was determined:

$$\mathrm{CONC} = 0.455\ \mathrm{CONC}_1 + 0.545$$

$$(\text{for } 0.75 \leq \mathrm{CONC}_1 \leq 1)$$

where CONC_1 is the concentration of the acid being produced in the acid plant, and CONC is the average concentration of the acid mist particles.

The value of sulfuric acid, VSA, is given in terms of its concentration, CONC, by:

$$\mathrm{VSA} = 50\ \mathrm{CONC} - 31 \qquad \text{\$/ton of acid}$$

$$(\text{for } 0.9 \leq \mathrm{CONC} \leq 1)$$

These two relations can be combined into one to give the sulfuric acid value in terms of the concentration of the acid plant product (see Figure 6.13):

$$\mathrm{VSA} = 22.75\ \mathrm{CONC} - 3.75 \qquad \text{\$/ton of acid}$$

$$(\text{for } 0.75 \leq \mathrm{CONC} \leq 1)$$

The credit value of the recovered SO_2, VSD, can be established in terms of the equivalent amount of sulfuric acid that can be produced from it:

$$\mathrm{VSD} = \frac{98.08}{64.06} \times \frac{1}{\mathrm{CONC}} \times \mathrm{VSA}\ (1-\mathrm{FR}) \qquad \text{\$/ton of acid}$$

where FR represents the operating costs in the acid plant as a fraction of the sulfuric acid value, VSA.

b) Sulfur Dioxide

The SO_2 production for the modified NIPSCO design is 4430 lbs/hr, and is proportional to the sulfur rate (from SO_2). For the reference plant at 100% load factor:

$$\text{Production} = 4430 \times 0.1452 \times \frac{8760}{2000} = 2820 \text{ tons/yr}$$

The SO_2 credit, ASD, is:

$$ASD = 2.82\left(\frac{S}{350}\right) VSD \cdot LF \qquad \text{M \$/yr}$$

where VSD is the credit value of SO_2 in \$/ton.

Using the previous relation, the SO_2 credit, ASD, can be obtained in terms of VSA as:

$$ASD = \frac{4.32}{CONC}\left(\frac{S}{350}\right) VSA\,(1-FR) \cdot LF \qquad \text{\$/ton of acid}$$

c) Purge Solids

The NIPSCO design shows a purge solids production rate of 0.35 tons/hr which is proportional to the sulfur rate. The purge solids flow for the reference plant at 100% load factor is:

$$\text{Production} = 0.35 \times 0.1452 \times 8760 = 450 \qquad \text{tons/yr}$$

The purge solids credit (or debit), APS, is:

$$APS = 0.45\left(\frac{S}{350}\right) VPS \cdot LF \qquad \text{M \$/yr}$$

where VPS is the unit value of the purge solids in \$/ton. If the purge solids are listed as a credit (debit), VPS would be positive (negative).

The total cost of raw materials and utilities less credits, ANR, is:

$$ANR = AS + AE + AH + ACW + AW + AF - ASA - ASD - APS \quad \text{M \$/yr}$$

6.2.4 Total Plant Investment and Total Capital Required

The bare cost of the control plant (BARC), total plant investment (TPI), and total capital required (TCR) for the Wellman-Lord system can be calculated from the appropriate equations in the General Cost Model.

$$BARC = 1.15\ (E + M) + 1.43\ L \cdot F \quad \text{M \$}$$

$$TPI = 1.12\ (1.0 + CONTIN) \cdot BARC \quad \text{M \$}$$

$$TCR = 1.135\ TPI + 0.2\ (AOC + CRED) \quad \text{M \$}$$

where $E = EA + ES + EP$ M \$

$L = LA + LS + LP$ M \$

$M = MA + MS + MP$ M \$

6.2.5 Operating Costs

The total net annual operating cost (AOC) is given by the following equation from the General Cost Model:

$$AOC = 0.078\ TPI + 2.0\ TO \cdot CO\ (1.0 + F) + ANR \quad \text{M \$/yr}$$

where TO = total number of shift operators

CO = hourly rate for an operator ($/hr)

For a 200 MW utility plant, the Wellman-Lord system requires 16 operators (4 per shift). In the model for utility boilers it was assumed that, for plants less than 200 MW, the number of operators was directly proportional to the plant size. Since the reference control plant used in this model handles a gas flow which is approximately equivalent to that from a 6 MW boiler, the number of operators required for the reference plant is:

$$(TO)_{ref.} = 16 \frac{6}{200} = 0.48$$

If it is further assumed that, for other plant sizes, the number of operators is directly proportional to the total gas flow, then,

$$TO = 0.48 \left(\frac{GP}{20}\right)$$

The total annual production cost, TAC, can then be calculated from the appropriate equation in section 5 as:

$$TAC = \frac{STC + TCR - 0.239\ WKC - 0.291\ TPI}{3.955} + AOC$$

where the working capital (WKC) and start-up costs (STC) are given by:

$$WKC = 0.2\ (AOC + CRED)$$

$$STC = 0.2\ (AOC + CRED)$$

6.2.6 Effect of Various Parameters on Costs

In Figures 6.14 to 6.16 typical costs which were calculated from the model have been plotted to illustrate the effects of different variables on costs. These plots are not for actual, existing plants, but have been included merely to illustrate typical cost variations predicted by the model. Although the figures are self-explanatory, some of the more significant conclusions should be noted.

Figure 6.14 shows that plant capacity has a large effect on the total capital requirement. Small plants are far more expensive to control than large ones. On an equivalent basis ($/ton of 100% acid annual plant capacity), a plant having an annual capacity of 2,000 M tons of 100% acid can be controlled for 15% to 18% of the cost required for a 10 M ton/yr plant.

Figures 6.15 and 6.16 show that plant capacity has a similar effect on operating costs. While a new 10 M ton/yr plant (Gulf Coast location) can be controlled at a cost ranging from 10 $/ton to 17 $/ton, a plant 200 times larger could be controlled for 1.8 $/ton to 3.2 $/ton.

Figures 6.14 and 6.15 also indicate how the costs vary with the amount of sulfur (from SO_2) in the gas. The values that were used (S_1=24 and S_1=54) represent the minimum and maximum encountered in existing acid plants (refer to Section 4.3). Increasing the SO_2 emissions from 24 to 54 pounds of sulfur per ton of 100% acid can increase the total capital requirement of the control unit by as much as 35%, and increase the operating costs of the control unit by as much as 50%.

The amount of acid mist in the gas does not have a noticeable effect on the total capital requirement because the mist eliminators are designed based on the total gas flow from the sulfuric acid plant. Since the recovered sulfuric acid is claimed as a credit, the acid mist content of the gas has a positive effect on production costs. As seen in Figure 6.16, increasing the acid mist emissions from 4 to 22 pounds of sulfur per ton of 100% acid may reduce the costs by as much as 23%.

The same figures also show the effect of the gas discharge on costs. For a 2000 M tons/yr plant, the total capital requirement could increase by 47% and the production cost by 58% when the amount of gas discharged increases from 92 to 192 M ACF per ton of 100% acid produced.

The influence of load factor on operating costs was not investigated because, on the average, most sulfuric acid plants operate at 95% of capacity, with only minor deviations from this figure. The effects of retrofit and location factors on costs are similar to those indicated in Part 1 of this study.

6.2.7 Wellman-Lord Model Applied to Existing Sulfuric Acid Plants

The Wellman-Lord stack gas scrubbing model has been applied to all the sulfuric acid plants contained in the data file mentioned in Section 4.3. A breakdown of costs, capacities and production for each state is presented in Table 6.5. The results of the analysis are presented graphically in Figures 6.17 to 6.25.

Figure 6.17 shows the total capital required for installing the stack gas scrubbing system in existing sulfuric acid plants of various sizes. Figure 6.18 presents the total capital requirement expressed in \$/ton of 100% annual acid capacity. This cost increases gradually with decreasing plant capacity from 2,000 to 100 M tons of 100% acid/yr, but rises sharply below 100 M tons/yr.

Figure 6.19 shows the estimated incremental production cost (\$/ton of acid) for installing the Wellman-Lord system in existing sulfuric acid plants. The incremental cost varies from about 8.5 \$/ton to 6.1 \$/ton for plant sizes of 100 to 2,000 M tons/yr. Below 100 M tons/yr, the incremental cost rises sharply with decreasing size.

The cumulative plant capacity (as percent of total capacity) is plotted against the maximum capital requirement in Figure 6.20. This plot shows that 90% of the total sulfuric acid capacity could be controlled at costs below 28 \$/ton of annual acid capacity, while the total U.S. capacity could be controlled at costs of 74 \$/ton of annual acid capacity or less. A similar graph for the maximum annual production cost is shown in Figure 6.21.

The cumulative total capital requirement (in MM\$) and production cost (in MM \$/yr) are plotted against percent of total capacity controlled in Figures 6.22 and 6.23 respectively. Similarly, the cumulative costs versus the reduction in sulfur emissions (as percent of total U.S. emissions from sulfuric acid plants) are shown in Figures 6.24 and 6.25

6.3 Industrial Boilers

6.3.1 Conventional Scrubbing System

In Part 1 of this study an investigation was made to determine the costs of fitting stack gas scrubbing processes to coal and oil fired industrial boilers in the U.S. With slight modifications, the cost models developed for utility boilers were used for this purpose. However, the costs predicted for small size industrial boilers (less than 100 MMBtu/hr) were found to be very high, mainly because these boilers represent a large extrapolation of the models from the type of application for which they were initially developed.

In this phase of the study, the cost models for utility boilers have been re-examined for application to small utility boilers. New reference sizes were determined for which equipment costs have been obtained from the correlations developed for the cost model for sulfuric acid plants (Section 6.2) and from price quotations for shop fabricated scrubbing units (Section 6.3.2).

The reference size control plants were chosen to handle a flue gas flow of 20,000 ACFM and a sulfur rate of 170 lbs/hr. This is approximately equivalent to the discharge from a 6 MW utility boiler.

The equipment cost equations derived for this reference size are presented in Table 6.6 and Table 6.7 for the wet limestone and Wellman/Allied systems respectively. These equations were found to be applicable for gas flow rates not greater than 110,000 ACFM and sulfur flow rates up to 1,000 lbs/hr. The cost models for utility boilers can then be applied beyond these points (for a detailed explanation of these equations refer to Sections 5 and 6 in Part I of this study). Tables 6.8 and 6.9 give a summary of the combined cost models for both processes.

These equations were implemented for computer application and were used to determine the costs for installing wet limestone and Wellman/Allied scrubbing on existing industrial boilers on a plant basis for all plants greater than 5 MW equivalent size. The control procedure that was used is the same as that for utility boilers, viz., controls are applied to individual boilers in a plant (in order of decreasing sulfur emissions) until the overall plant emission falls below the allowable level (1.2 lbs of SO_2/MMBtu).

After the data base was edited as discussed in section 4.2.3, it was found that among 4385 plants considered for cost analysis, only 829 plants required control. This represents about 19% of the plants considered.

Table 6.10 and 6.11 give the breakdown of costs for each state for both Wellman/Allied and wet limestone processes.

Figures 6.26 and 6.27 represent graphically the average total capital requirement for installing Wellman/Allied and wet limestone stack gas scrubbing units in existing industrial boiler plants. Only plants requiring control are included in these cost curves. These graphs show that the wet limestone process is somewhat less expensive, although at a plant size less than 50 MMBtu/hr, there is no distinct difference between the two processes.

Figures 6.28 and 6.29 represent the variation in average annual production cost for both processes. The cost in $/MMBtu decreases with increasing plant size.

Figure 6.30 represents the maximum total capital requirement, in $/MMBtu/yr, versus the cumulative plant capacity expressed as a percentage of the total capacity of controlled plants. This curve shows the cost of controlling any given percentage of the total US plant capacity.

Figure 6.31 shows the same type of relationship between the maximum total production cost, in $/MMBtu, and the cumulative plant capacity of controlled plants, expressed in %.

Figure 6.32 shows the cumulative total capital requirement, in MM$, versus the cumulative plant capacity of controlled plants, expressed in %. Only one curve was drawn since there was no difference in the cost between the two processes. The summation was made in order of increasing TCR ($/MMBtu/yr). Figure 6.33 is a similar plot except that the summation was made in order of decreasing plant size.

Figures 6.34 and 6.35 show the cumulative production cost, in MM$/yr, versus the cumulative plant production, expressed as % of the total US controlled plants. The summation in the first curve was made in order of increasing TAC ($/MMBtu) and the second one in order of decreasing plant production.

Figures 6.36 and 6.37 show the reduction in sulfur emission, expressed in %, versus the cumulative total capital requirement, in MM$, and the cumulative production cost, in MM$/yr.

6.3.2 Packaged Scrubbing System

1. Objective

The objective of this phase of the study was to develop a cost estimate for shop fabrication and packaging of a scrubber unit as a possible investment alternative to reduce capital expense and make scrubbing more economically practical. The scrubbing system selected is the wet limestone scrubbing system to serve a 50 MMBtu/hr coal fired boiler (single boiler plant). This size boiler was selected on the basis of the minimum size referred to in the EPA task description.

"Packaged system" refers to a scrubbing system which consists of several preassembled units. It differs from a normal installation in the sense that field erection cost is minimized. The major equipment is combined into sections at the shop and arrives at the job site in single units as opposed to having each separate piece of equipment installed in the field.

Ideally, a skid-mounted unit for the entire scrubbing system would represent the minimum field erection cost, but this proved to be impractical due to the equipment sizes and shipping dimensions allowed.

As an alternate to a skid-mounted system some of the major equipment pieces can be combined as packaged sections. Two sections have been assembled as follows.

1) The venturi and TCA scrubbers are mounted on the scrubber sump at the shop and shipped as a unit. All lining, required instrumentation and internal piping

is completed at the shop.

2) The gas reheater and entrainment separator are shop assembled as a packaged section, including the ductwork and transition pieces.

This ductwork consists of sections from the TCA scrubber to the entrainment separator, from the entrainment separator to the reheater and a short section from the reheater.

The rest of the equipment is shop fabricated, including lining where required.

2. Basis of Design

The limestone slurry scrubbing system was designed to be part of a steam generating plant having a single 50 MMBtu/hr coal-fired boiler.

Fuel to Boiler - The boiler will be fueled with 4200 lbs/hr of coal with a sulfur content of 3.5 weight percent and an ash content of 14.5 weight percent.

Gas to Scrubbing System - Gas entering the scrubbing system is 18,000 ACFM @ 300°F and atmospheric pressure (12,300 SCFM) with an SO_2 rate of 300 lbs/hr and a solids rate of 500 lbs/hr (4.74 gr solids/SCFM).

Process - The limestone scrubbing system is based on the Catalytic design (3).

Equipment - A detailed description of the equipment is given in Appendix F.

Figure 6.38 - Shows the location of all the equipment. The settling pond has been assumed to be onsite but located in a remote section of the plant.

Figure 6.39 - Shows the plan view, side view and elevation for the equipment included in the scrubbing section. Over all dimensions are 52 ft wide by 69 ft long with an elevation of 74 ft.

3. Costs

All equipment prices included in the "packaged unit" were obtained from individual manufacturers and quoted as "budget price".

Basis for Cost Estimate

1) The plant will be constructed in the Midwest area where Cincinnati construction labor rates apply.

2) The venturi and TCA scrubbers will be mounted on the scrubber sump at the shop and shipped as a unit. All lining, required instrumentation and internal piping will be completed at the shop.

3) All vessels that require lining will be completely shop assembled.

4) The gas reheater and entrainment separator will be shop assembled as a unit, including the ductwork and transition pieces. The ductwork consists of the duct from the TCA scrubber, duct to and from entrainment separator, duct to and from the gas reheater.

5) All ductwork will be lined at the shop.

6) The ductwork from the boiler to the venturi scrubber is shipped as a single piece.

7) The effluent gas duct, from the gas reheater duct to the I.D. fan, is shipped in two sections due to shipping length limitations.

8) All pumps are base mounted.

9) Tank agitators will be shipped fully assembled and ready to be mounted on top of the corresponding tanks.

10) The belt conveyor will be shipped in four sections due to shipping length limitations.

Comparison With Field Erected Unit

The costs of a packaged versus field erected wet limestone scrubbing unit for a 50 MM Btu/hour boiler are summarized in Table 6.12. The total capital required, TCR, for a packaged unit was estimated to be $3493M (about $8/MM Btu/year) compared to $4364M (about $10/MM Btu/year) for a field erected unit, a potential savings of 20%. However, in view of the 20-25% accuracy of the wet limestone cost model, which was used to generate costs for the field erected unit, the only conclusion that can be drawn from the cost comparison is that a packaged system appears to offer some potential for reducing capital costs, but the magnitude of the cost savings is uncertain.

Operating costs are about $3.20/MM Btu for a packaged unit compared to $3.90/MM Btu for a field erected unit. This difference is related to capital charges.

6.4 Wellman/Allied Model Applied to Claus Plants

The Wellman/Allied process and cost model presented in Part 1 has been re-examined in order to determine what modifications would be necessary to make it applicable to Claus sulfur recovery plants.

Information on the tail gas discharge from Claus plants has been obtained from the report "Characterization of Claus Plants Emissions" prepared by Process Research, Inc. (19) It should be pointed out that the main body of this report gives the sulfur dioxide flow rate as a function of the number of catalytic stages and the amount of hydrogen sulfide in the gas feed. This information is insufficient to completely characterize the emissions. However, the Appendix of the report contains some data provided by companies that are operating Claus plants.

The available information indicated that, after incineration, the tail gas from Claus plants is at a temperature that ranges from 850°F to 1,300°F and normally contains from 1.0% to 1.6% (by volume) of SO_2. These figures have been compared with available figures in the NEDS Claus plant file, and seem to be representative. As a result of incineration and the Claus process itself, the gas also contains large amounts (25% to 33%) of water vapor.

The temperature of the flue gas is much too high to be fed directly into the absorber. A small sized boiler can be designed to utilize part of this heat to generate steam and cool the hot gas down to about 300°F. It is estimated that this boiler could provide from 80% to 90% of the steam required by the evaporator system in the SO_2 recovery section. This can be claimed as a credit.

A water cooled heat exchanger can then be used to further reduce the temperature of the gas to the operating temperature in the absorber. At this point the gas will be saturated with water vapor and some water will have condensed. The gas can enter the absorber after the condensate is removed.

The cost model developed for utility boilers is based on the design for the demonstration plant being installed at the D.H. Mitchell plant of the Northern Indiana Public Service Company (NIPSCO). This design includes quench pumps and a prescrubbing section in the absorber where the gas is scrubbed by recirculating water to remove the flyash. The gas becomes saturated with water vapor and its temperature is reduced in this same process. These sections can therefore be effectively eliminated in the present case since the tail gas from Claus plants does not contain any flyash and is already saturated with water vapor after going through the cooling process described above.

The NIPSCO absorber is designed to handle a gas that contains approximately 0.2% SO_2. Perforated trays without downcomers are used for this purpose. The liquid is recirculated to each tray in order to maintain an effective liquid level. The gas from Claus plants will enter the absorber with an SO_2 concentration ranging from 1.2 to 1.8% by volume. Under these conditions, the liquid (sodium sulfite solution) flow rate is greater and a higher bisulfite concentration can be obtained as a product. A normal perforated tray tower design appears to be feasible and more economical because the circulating pumps can then be eliminated and the costs reduced. This cost reduction will be partly off-set by the increased cost of the tower internals. The rest of the equipment in the plant (shown as proportional to the sulfur rate in the model for utility boilers) will then have to be scaled to provide enough capacity to handle the higher liquid rate and bisulfite concentration. For similar gas flows, it is estimated that this equipment has to be 4 to 6 times larger than the corresponding equipment used in the process for utility boilers.

Equipment such as the flyash filter and the absorber surge tank and pump can be eliminated from the design since they are related to flyash removal. The liquid from the absorber can be fed directly into the evaporator feed tank, which will have to be enlarged to provide enough surge capacity.

The Allied section for sulfur recovery need not be included in the model since the recovered sulfur dioxide can be directly recycled as a feed to the Claus plant.

The tail gas discharge rate from Claus plants is much less than the flue gas flow from most utility boilers. Therefore, a smaller reference size plant should be used as a basis for the cost model. Only single trains appear to be necessary for each process section. The cost correlations for small size equipment developed for the model for sulfuric acid plants would then be applicable.

Finally, it is important to point out that further studies are required to fully characterize the emissions from Claus plants. A cost model can only be applied to existing plants if the tail gas flow rate, composition and temperature can be predicted from plant characteristics such as production capacity, number of catalytic stages, and feed gas composition.

6.4.1 Equipment Costs

For application to Claus plants, the Wellman/Allied process and cost model for utility boilers will have to be modified as follows:

1) Absorber Area

The following equipment can be eliminated from this area:

a) Quench pumps
b) Prescrubber section of the absorption tower, including lining and internals
c) Prescrubber circulation pumps
d) Absorber internals
e) Absorber circulation pumps

These costs will then be replaced by:

a) Cooling system, which will include:

  - Boiler
  - Steam drum
  - Heat exchanger
  - Separating drum
  - Booster fan
  - Pumps

b) Modified tower internals (new tray design)

2) SO_2 Regeneration Area

Equipment that can be deleted from this section:

a) Flyash filter
b) Absorber surge tank, agitator, and pump

Other equipment costs in this area need to be adjusted to reflect the increase in capacity due to the higher liquid and sulfur flow rates. In the absence of the absorber surge tank, the evaporator feed tank has to be enlarged to provide enough surge capacity.

3) Purge/Make-up Area

Equipment costs in this area are proportional to the sulfur flow rate and, as before, need to be adjusted for the higher flow rates.

4) Reduction Area

This area can be eliminated from the model since the sulfur dioxide would be recycled to the Claus plant.

6.4.2 Raw Materials and Utilities

The consumption of raw materials and utilities will have to be modified according to the process and equipment indicated above.

6.4.3 Credits

1) Since the Allied section can be excluded from the model, the sulfur credit has to be eliminated and replaced by a sulfur dioxide credit.

2) The purge solids credit (debit) will have to be modified according to the new process.

3) The steam produced in the boiler can also be listed as a credit.

6.4.4 Reference Size

A smaller (more representative) reference size plant is recommended to be used as a basis for the modified cost model. Statistics on existing Claus plants indicate that a multitrain system will not be necessary.

TABLE 6.1

STACK GAS SCRUBBING COST ANALYSIS
FUEL ALLOCATED TO BOILERS

PLANT NO --- 1 OF UTILITY -- 2 STATE---ALABAMA
PLANT SIZE--- 1771 MEGAWATTS
NO. OF BOILERS 5

BOILER FUEL CONSUMPTION & SULFUR EMISSION DATA
(UNCONTROLLED)

THE BOILERS ARE ARRANGED IN ORDER OF DECREASING SULFUR EMISSIONS AND THIS IS THE ORDER IN WHICH THE CONTROLS ARE APPLIED

BOILER SIZE (MEGAWATTS)	FUEL BURNED (MMMBTU)	SULFUR EMISSION (MTON/YEAR)	SULFUR EMISSION (TON/YR/MEGAWATT)
789	32025.23	34.65	43.92
404	11806.73	12.77	31.62
272	5802.39	6.28	23.08
153	1159.20	1.25	8.20
153	1159.20	1.25	8.20

FUEL CONSUMPTION,SULFUR EMISSION & CONTROL COST DATA
METHOD OF CONTROL--WELLMAN-LORD PROCESSFRACTION OF SO2 REMOVED-- 0.95

NO. OF BOILERS CONTROLLED	% PLANT CAP (CONTROLLED)	% PLANT FUEL BURNED BY CONTROLLED BOILERS	TOT CAP REQ (CUMMULATIVE)		T A C			SULFUR REMOVED MTONS/YEAR	OVERALL PLANT SO2 EMISSION LBS/MMBTU
			MM$	$/KW	MILS/ KWH.	C/MMBTU	$/TON SULFUR REMOVED		
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.33
1	44.55	61.64	43.835	55.56	3.31	36.77	357.71	32.92	1.79
2	67.36	84.37	64.896	54.40	3.51	39.02	379.63	45.05	0.86

TABLE 6.2

STACK GAS SCRUBBING COST ANALYSIS
ACTUAL PLANT DATA

```
                    ****************************************************************************************
PLANT NO. -  1 OF UTILITY NO. -   1  UTILITY NAME-
PLANT NAME & ADDRESS-                                                                          STATE -ALABAMA
********************
UTIILITY CODE -          PLANT CODE-                                                               STATE CODE:  1
*************            **********                                                                 AQCR CODE:  5
PLANT SIZE - 1770MEGAWATTS  NUMBER OF BOILERS-  5                DATA VALIDITY CODE - 0  *         COUNTY CODE: 97

                         BOILER FUEL CONSUMPTION & SULFUR EMISSION DATA
                                         (UNCONTROLLED)

THE BOILERS ARE ARRANGED IN ORDER OF DECREASING SULFUR EMISSIONS AND
THIS IS THE ORDER IN WHICH THE CONTROLS ARE APPLIED

      BOILER SIZE        FUEL BURNED    SULFUR EMISSION      SULFUR EMISSION
      (MEGAWATTS)        (MMBTU)         (MTON/YEAR)        ( TON/YR/MEGAWATT)
      -----------        -----------    ---------------      --------------

        403               17831.76         17.97                 44.59
        272               13412.33         13.75                 50.53
        153                8009.79          8.50                 55.57
        788                9510.35          8.43                 10.70
        153                7783.63          7.89                 51.60


                        FUEL CONSUMPTION,SULFUR EMISSION & CONTROL COST DATA
                        METHOD OF CONTROL--WELLMAN-LORD PROCESSFRACTION OF SO2 REMOVED-- 0.95

NO. OF       % PLANT CAP  % PLANT FUEL    TOT CAP REQ            T     A     C          SULFUR REMOVED   OVERALL PLANT
BOILERS      (CONTROLLED)  BURNED BY     (CUMMULATIVE)         MILS/  C/MMBTU $/TON     MTONS/YEAR      SO2 EMISSION
CONTROLLED                 CONTROLLED    MM$       $/KW        KWH.           SULFUR                    LBS/MMBTU
                           BOILERS                                            REMOVED
----------   ----------   -----------   ----------------      ------------------------   -------------   -------------

     0            0.0          0.0        0.0        0.0        0.0       0.0     0.0
     1           22.77        31.53      21.509     53.37       3.25     33.49  349.78          0.0           4.00
     2           38.14        55.25      34.004     50.38       2.94     30.04  311.53         17.07          2.79
     3           46.78        69.42      42.254     51.03       2.87     29.56  303.66         30.13          1.87
     4           91.30        86.24      77.659     48.06       3.93     39.83  420.24         38.21          1.30
                                                                                            46.22          0.73
 *
      CODE                EXPLANATION
      ****                ***********
      0    DATA IS SUFFICIENT FOR COST ANALYSIS
      3 OR MORE  DATA INSUFFICIENT FOR COST ANALYSIS
```

TABLE 6.3

EPA STACK GAS SCRUBBING COST ANALYSIS SYSTEM

SUMMARY OF COSTS BY STATES - WET LIMESTONE PROCESS APPLIED TO UTILITY PLANTS

STATE	TOTAL CAPACITY MW	TOTAL PRODUCTION MWH	TOTAL TCR M$	AVERAGE TCR $/KW	TOTAL TAC M$	AVERAGE TAC MILS/KWHR
ALABAMA	7607.00	36687168.00	346857.31	45.60	91741.36	2.50
ALASKA	0.0	0.0	0.0	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.0	0.0	0.0	0.0
ARKANSAS	179.00	777158.75	10752.10	60.07	2724.40	3.51
CALIFORNIA	0.0	0.0	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0	0.0	0.0	0.0
CONNECTICUT	1683.00	8357606.00	186424.75	110.77	48101.29	5.77
DELAWARE	766.00	4440371.00	38111.90	49.75	9904.30	2.23
D.C.	0.0	0.0	0.0	0.0	0.0	0.0
FLORIDA	8009.00	43739168.00	427309.00	53.35	119470.00	2.73
GEORGIA	5333.00	25451616.00	370480.81	69.47	94062.81	3.70
HAWAII	0.0	0.0	0.0	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0	0.0	0.0	0.0
ILLINOIS	6027.00	27371968.00	442036.00	73.34	116319.36	4.25
INDIANA	4456.00	28709888.00	522809.69	117.33	138871.13	4.84
IOWA	1458.00	8071845.00	163310.13	112.01	41391.18	5.13
KANSAS	400.00	1436026.00	12372.90	30.93	3127.90	2.18
KENTUCKY	8773.00	45792848.00	652009.06	74.32	172134.56	3.76
LOUISIANA	0.0	0.0	0.0	0.0	0.0	0.0
MAINE	214.00	1382090.00	20150.60	94.16	6092.60	4.41
MARYLAND	3474.00	18288288.00	156157.81	44.95	43434.19	2.37
MASSACHUSETT	2753.00	16809168.00	170085.88	61.78	50692.29	3.02
MICHIGAN	7019.00	41924352.00	510134.69	72.68	134866.06	3.22
MINNESOTA	1737.00	8843770.00	158897.44	91.48	40209.29	4.55
MISSISSIPPI	220.00	1199296.00	5092.20	23.15	1375.80	1.15
MISSOURI	5975.00	28305808.00	365739.94	61.21	96741.13	3.42
MONTANA	222.00	1013373.94	20132.20	90.69	5003.20	4.94
NEBRASKA	1015.00	4889986.00	43455.59	42.81	10580.39	2.16
NEVADA	0.0	0.0	0.0	0.0	0.0	0.0
NEW HAMPSHIR	637.00	3747792.00	38762.70	60.85	10723.30	2.86
NEW JERSEY	653.00	3755322.00	38081.30	58.32	9893.50	2.63
NEW MEXICO	0.0	0.0	0.0	0.0	0.0	0.0
NEW YORK	4059.00	22308896.00	471794.13	116.23	123916.50	5.55
N. CAROLINA	5762.00	37882304.00	163317.69	28.34	44218.39	1.17
NORTH DAKOTA	744.00	5204795.00	57204.39	76.89	15594.79	3.00
OHIO	12003.00	69599520.00	1093378.00	91.09	286762.06	4.12
OKLAHOMA	0.0	0.0	0.0	0.0	0.0	0.0
OREGON	0.0	0.0	0.0	0.0	0.0	0.0
PENNSYLVANIA	12604.00	68063568.00	904659.88	71.78	236439.06	3.47
RHODE ISLAND	165.00	1228589.00	40252.40	243.95	9543.60	7.77
S. CAROLINA	2390.00	12558511.00	71644.88	29.98	18744.49	1.49
SOUTH DAKOTA	123.00	238096.50	15498.10	126.00	3591.50	15.08
TENNESSEE	5958.00	30643872.00	369853.81	62.08	97230.13	3.17
TEXAS	593.00	3480433.00	29144.80	49.15	7753.40	2.23
UTAH	0.0	0.0	0.0	0.0	0.0	0.0
VERMONT	30.00	122201.88	6556.20	218.54	1466.00	12.00
VIRGINIA	3932.00	21635312.00	246351.81	62.65	70660.88	3.27
WASHINGTON	0.0	0.0	0.0	0.0	0.0	0.0
W. VIRGINIA	6558.00	39629312.00	461189.56	70.32	123514.88	3.12
WISCONSIN	4275.00	22343008.00	504948.31	118.12	127449.31	5.70
WYOMING	456.00	2571041.00	25156.90	55.17	6265.70	2.44

TABLE 6.4

EPA STACK GAS SCRUBBING COST ANALYSIS SYSTEM

.SUMMARY OF COSTS BY STATES - WELLMAN/ALLIED PROCESS APPLIED TO UTILITY PLANTS

STATE	TOTAL CAPACITY MW	TOTAL PRODUCTION MWH	TOTAL ICR M$	AVERAGE ICR $/KW	TOTAL TAC M$	AVERAGE TAC MILS/KWHR
ALABAMA	7607.00	36687168.00	377910.38	49.68	103340.94	2.82
ALASKA	0.0	0.0	0.0	0.0	0.0	0.0
ARIZONA	0.0	0.0	0.0	0.0	0.0	0.0
ARKANSAS	179.00	777158.75	12256.80	68.47	5280.00	4.23
CALIFORNIA	0.0	0.0	0.0	0.0	0.0	0.0
COLORADO	0.0	0.0	0.0	0.0	0.0	0.0
CONNECTICUT	1683.00	8337606.00	184236.63	109.47	49492.59	5.94
DELAWARE	766.00	4440371.00	38782.89	50.63	10591.60	2.39
D.C.	0.0	0.0	0.0	0.0	0.0	0.0
FLORIDA	8009.00	43739168.00	551221.56	68.83	157868.63	3.61
GEORGIA	5333.00	25451616.00	314146.88	58.91	81901.44	3.22
HAWAII	0.0	0.0	0.0	0.0	0.0	0.0
IDAHO	0.0	0.0	0.0	0.0	0.0	0.0
ILLINOIS	6027.00	27371968.00	487773.31	80.93	135006.31	4.86
INDIANA	4456.00	28709888.00	473795.38	106.33	132243.25	4.61
IOWA	1458.00	8071845.00	146620.38	100.56	38456.48	4.76
KANSAS	400.00	1436026.00	12618.90	31.55	3352.50	2.33
KENTUCKY	6773.00	45742848.00	657193.69	72.63	175540.19	3.83
LOUISIANA	0.0	0.0	0.0	0.0	0.0	0.0
MAINE	214.00	1382090.00	20884.70	97.59	6436.10	4.66
MARYLAND	3474.00	18288288.00	164922.38	47.47	46185.29	2.53
MASSACHUSETT	2753.00	16809168.00	255161.63	92.68	76924.19	4.58
MICHIGAN	7019.00	41924352.00	461100.19	65.69	127906.06	3.05
MINNESOTA	1737.00	6843770.00	145132.19	82.40	37727.59	4.27
MISSISSIPPI	220.00	1199296.00	6940.80	31.55	1947.50	1.62
MISSOURI	5975.00	28305808.00	398335.00	66.67	109446.44	3.87
MONTANA	222.00	1013373.94	18153.70	81.77	4821.80	4.76
NEBRASKA	1015.00	4889986.00	34430.80	33.92	8808.00	1.80
NEVADA	0.0	0.0	0.0	0.0	0.0	0.0
NEW HAMPSHIR	637.00	3747792.00	39605.80	62.18	11423.70	3.05
NEW JERSEY	653.00	3755322.00	36129.50	55.33	9907.20	2.64
NEW MEXICO	0.0	0.0	0.0	0.0	0.0	0.0
NEW YORK	4059.00	22308896.00	500604.19	123.33	138872.38	6.22
N. CAROLINA	5762.00	37882304.00	146131.63	25.36	41432.29	1.09
NORTH DAKOTA	744.00	5204795.00	53888.80	72.43	15486.50	2.98
OHIO	12003.00	64599520.00	1013465.06	84.43	278649.31	4.00
OKLAHOMA	0.0	0.0	0.0	0.0	0.0	0.0
OREGON	0.0	0.0	0.0	0.0	0.0	0.0
PENNSYLVANIA	12604.00	68063568.00	820913.94	65.13	224098.94	3.29
RHODE ISLAND	165.00	1228589.00	40164.80	243.42	10216.30	8.32
S. CAROLINA	2390.00	12558511.00	64273.06	28.98	18993.79	1.51
SOUTH DAKOTA	123.00	238096.50	19352.59	157.34	4605.70	19.34
TENNESSEE	5958.00	30643872.00	327630.56	54.99	90015.51	2.94
TEXAS	593.00	3480433.00	20116.30	33.92	5698.90	1.64
UTAH	0.0	0.0	0.0	0.0	0.0	0.0
VERMONT	30.00	122201.88	6137.60	204.59	1452.20	11.72
VIRGINIA	5932.00	21635312.00	372461.31	94.73	106948.19	4.94
WASHINGTON	0.0	0.0	0.0	0.0	0.0	0.0
W. VIRGINIA	6558.00	39629312.00	428209.13	65.30	120300.38	3.04
WISCONSIN	4275.00	22343008.00	396965.69	92.86	105259.19	4.71
WYOMING	456.00	2571041.00	21008.60	46.07	5394.40	2.10

TABLE 6.5

SUMMARY OF STACK GAS SCRUBBING COSTS BY STATES
WELLMAN-LORD PROCESS APPLIED TO SULFURIC ACID PLANTS

STATE	TOTAL CAPITAL REQUIREMENT (M$)	TOTAL ANNUAL PRODUCTION COST (M$/YR)	TOTAL CAPACITY M TONS OF 100% ACID PER YEAR	TOTAL PRODUCTION M TONS OF 100% ACID PER YEAR	AVERAGE TCR ($/TON/YR)	AVERAGE TAC ($/TON)
ALABAMA	10,950	3,004	337.8	326.8	32.41	9.19
ALASKA						
ARIZONA	17,099	4,858	636.8	605.5	26.85	8.02
ARKANSAS	9,069	2,565	432.9	415.3	20.95	6.18
CALIFORNIA	50,662	14,378	2,209.7	2,108.6	22.93	6.82
COLORADO	3,228	887	116.1	107.6	27.81	8.25
CONNECTICUT						
DELAWARE	7,330	2,089	426.3	407.6	20.08	5.97
FLORIDA	147,475	43,257	9,421.0	9,923.4	15.65	4.90
GEORGIA	20,617	5,734	641.8	612.3	32.12	9.37
HAWAII	1,272	350	127.9	120.0	31.58	9.13
IDAHO	17,590	5,092	858.5	820.8	20.49	6.20
ILLINOIS	53,599	15,252	2,619.0	2,493.1	20.47	6.12
INDIANA	17,921	5,027	720.0	672.0	24.86	7.48
IOWA	10,993	3,171	624.8	599.5	17.59	5.29
KANSAS	6,512	1,850	248.9	236.8	26.16	7.81
KENTUCKY	5,809	1,624	264.6	254.0	21.95	6.39
LOUISIANA	59,018	17,332	4,215.0	4,018.8	14.00	4.31
MAINE						
MARYLAND	18,658	5,209	746.6	713.9	24.99	7.30
MASSACHUSETTS	1,308	631	219.0	210.0	21.08	6.01
MICHIGAN	8,553	2,377	313.6	301.2	27.27	7.89
MINNESOTA	2,924	832	150.7	144.0	25.29	7.53
MISSISSIPPI	5,783	1,677	277.0	263.6	20.87	6.36
MISSOURI	14,983	4,227	651.2	625.8	23.01	6.75
MONTANA	4,157	1,199	315.4	302.4	26.36	8.06
NEBRASKA						
NEVADA	3,707	1,067	297.8	278.4	26.45	8.55
NEW HAMPSHIRE						
NEW JERSEY	49,762	14,072	2,352.1	2,261.4	21.16	6.22
NEW MEXICO	5,467	1,547	192.7	185.3	28.37	8.35
NEW YORK	4,467	1,249	208.0	202.0	21.47	6.18
NORTH CAROLINA	20,643	6,050	1,292.5	1,233.2	15.97	4.91
NORTH DAKOTA						
OHIO	19,866	5,597	766.5	727.6	25.92	7.69
OKLAHOMA	5,441	1,544	196.2	177.6	27.73	8.69
OREGON						
PENNSYLVANIA	24,160	6,810	929.1	897.6	26.00	7.59
RHODE ISLAND	877	238	200.0	196.3	50.08	14.61
SOUTH CAROLINA	7,058	1,928	137.5	129.5	51.32	14.88
SOUTH DAKOTA						
TENNESSEE	19,470	5,705	1,153.0	1,111.0	16.89	5.14
TEXAS	72,960	20,779	3,915.4	3,756.5	18.63	5.53
UTAH	17,190	5,019	613.2	578.9	28.03	8.67
VERMONT						
VIRGINIA	18,854	5,252	661.9	630.9	28.49	8.32
WASHINGTON	4,549	1,269	124.4	115.2	36.57	11.02
WEST VIRGINIA	3,058	878	184.0	168.0	21.82	6.77
WISCONSIN	3,443	942	109.5	105.0	31.45	8.97
WYOMING	3,337	930	113.9	109.4	29.30	8.50
D.C.						
PLANT TYPE						
1	35,995	9,881	733.1	691.2	49.10	14.30
2	270,982	76,999	12,257.4	11,638.8	22.11	6.62
3	199,466	58,351	13,896.0	13,180.0	14.35	4.43
4	188,054	53,675	8,008.7	7,627.5	23.48	7.04
5	86,319	24,593	4,292.8	4,105.9	20.11	5.99

TABLE 6.6

EQUIPMENT COST EQUATIONS FOR WET LIMESTONE PROCESS APPLIED TO SMALL INDUSTRIAL BOILERS

$$EC = \sum_{i=1}^{NA} RB_i \left[130 \left(\frac{GT_i}{20}\right)^{0.6} + 14.1 \left(\frac{GT_i}{20}\right)^{0.8} \right] + 17.9\ RP \left(\frac{GP}{20}\right)^{0.5} + 15.8 \left(\frac{S}{170}\right)^{0.4} \qquad M\$$$

$$ES = 29.6 \left(\frac{S}{170}\right)^{0.3} + 17.4 \left(\frac{S}{170}\right)^{0.5} \qquad M\$$$

$$P = 258 \left(\frac{S \cdot LF}{170}\right)^{0.6} \qquad M\$$$

$GP \leq 110$ M ACFM

$S \leq 1000$ lbs/hr

Note: See Appendix J for Explanation of Symbols

TABLE 6.7

EQUIPMENT COST EQUATIONS FOR WELLMAN/ALLIED PROCESS APPLIED TO SMALL INDUSTRIAL BOILERS

$$EA = \sum_{i=1}^{NAT} RB_i \left[15.2 \left(\frac{GT_i}{20}\right)^{0.5} + 46.1 \left(\frac{GT_i}{20}\right)^{0.6} + 40 \left(\frac{GT_i}{20}\right)^{0.8} + 39.3 \left(\frac{GT_i}{20}\right)^{0.9} \right] + 25.8\ RP \left(\frac{GP}{20}\right) + 20.7 \left(\frac{S}{170}\right)^{0.5} + 14.7\ IF \left(\frac{S}{170}\right)^{0.6} \quad M\$$$

$$ES = 42.1 \left(\frac{S}{170}\right)^{0.6} + 39.6 \left(\frac{S}{170}\right)^{0.7} + 9.5 \left(\frac{S}{170}\right)^{0.8} \quad M\$$$

$$EP = 54.7 \left(\frac{S}{170}\right)^{0.5} + 28.2 \left(\frac{S}{170}\right)^{0.8} \quad M\$$$

$$ER = 51 \left(\frac{S}{170}\right)^{0.7} + 26.6 \left(\frac{S}{170}\right)^{0.8} \quad M\$$$

$GP \leq 110$ M ACFM

$S \leq 1000$ lbs/hr

Note: See Appendix J for Explanation of Symbols

TABLE 6.8

WET LIMESTONE PROCESS AND COST MODEL FOR INDUSTRIAL BOILERS

SUMMARY OF EQUATIONS

If $GT_i \le 110$ M ACFM:

$$EC1_i = RB_i \left[130 \left(\frac{GT_i}{20}\right)^{0.6} + 14.1 \left(\frac{GT_i}{20}\right)^{0.8} \right] \quad M\$$$

If $GT_i > 110$ M ACFM:

$$EC1_i = RB_i \left[1041 \left(\frac{GT_i}{550}\right)^{0.5} + 408 \left(\frac{GT_i}{550}\right)^{0.9} \right] NA \quad M\$$$

where $GT_i = \frac{GP}{NA}$

then, for the plant, $EC1 = \sum_{i=1}^{NA} EC1_i$ M$

If $GP \le 110$ M ACFM:

$$EC2 = 17.9\ RP \left(\frac{GP}{20}\right)^{0.5} \quad M\$$$

If $Gp > 110$ M ACFM:

$$EC2 = 238\ RP \left(\frac{GP}{3300}\right)^{0.5} \quad M\$$$

If $S \le 1000$ lbs/hr:

$$EC3 = 15.8 \left(\frac{S}{170}\right)^{0.4} \quad M\$$$

$$ES = 29.6 \left(\frac{S}{170}\right)^{0.3} + 17.4 \left(\frac{S}{170}\right)^{0.5} \quad M\$$$

$$P = 258 \left(\frac{S \cdot LF}{170}\right)^{0.6} \quad M\$$$

If $S > 1000$ lbs/hr:

$$EC3 = 201 \left(\frac{SF}{28}\right)^{0.5} \quad M\$$$

$$ES = 1680 \left(\frac{SF}{28}\right)^{0.9} \quad M\$$$

TABLE 6.8 (CONTINUED)

$$P = 5000 \left(\frac{SF \cdot LF}{28}\right)^{0.9} \qquad \text{M\$}$$

where $SF = \frac{S}{1000}$

For the plant:

$$EC = EC1 + EC2 + EC3 \qquad \text{M\$}$$

$$E = EC + ES \qquad \text{M\$}$$

$$L = 0.39\ EC + 0.18\ ES \qquad \text{M\$}$$

$$M = 0.82\ EC + 0.09\ ES \qquad \text{M\$}$$

$$AL = 600\ CL \cdot LF \left(\frac{SF}{28}\right) \qquad \text{M\$/yr}$$

$$AA = 0.43\ CA \left(\frac{SF}{28}\right) \qquad \text{M\$/yr}$$

$$AW = 230\ CW \cdot LF \left[\left(\frac{GP}{3300}\right) + \left(\frac{SF}{28}\right) \right] \qquad \text{M\$/yr}$$

$$AF = 1{,}800\ CF \cdot LF \left(\frac{GP}{3300}\right) \qquad \text{M\$/yr}$$

$$AE = CE \cdot LF \left[213 \left(\frac{GP}{3300}\right) + 35 \left(\frac{SF}{28}\right) \right] \qquad \text{M\$/yr}$$

$$ANR = AL + AA + AW + AF + AE \qquad \text{M\$/yr}$$

$$BARC = 1.15\ (E + M) + (P + 1.43\ L)\ F \qquad \text{M\$}$$

$$TPI = 1.12\ (1.0 + CONTIN)\ BARC \qquad \text{M\$}$$

$$AOC = 0.078\ TPI + 2.0\ TO \cdot CO\ (1.0 + F) + ANR \qquad \text{M\$/yr}$$

$$WKC = 0.2\ AOC \qquad \text{M\$}$$

$$STC = 0.2\ AOC \qquad \text{M\$}$$

$$TCR = 1.135\ TPI + WKC \qquad \text{M\$}$$

$$TAC = \frac{STC + TCR - 0.239\ WKC - 0.291\ TPI}{3.955} + AOC \qquad \text{M\$/yr}$$

TABLE 6.9

WELLMAN/ALLIED PROCESS AND COST MODEL FOR INDUSTRIAL BOILERS

SUMMARY OF EQUATIONS

If $GT_i \leq 110$ M ACFM:

$$EA1_i = RB_i \left[15.2 \left(\frac{GT_i}{20}\right)^{0.5} + 46.1 \left(\frac{GT_i}{20}\right)^{0.6} + 40.0 \left(\frac{GT_i}{20}\right)^{0.8} + 39.3 \left(\frac{GT_i}{20}\right)^{0.9} \right] \qquad \text{M\$}$$

If $GT_i > 110$ M ACFM:

$$EA1_i = RB_i \left[726 \left(\frac{GT_i}{550}\right)' + 639 \left(\frac{GT_i}{550}\right)' \right] NAT \qquad \text{M\$}$$

where $GT_i = \frac{GP}{NAT}$

then, for the plant, $EA1 = \sum_{i}^{NAT} EA1_i$ M$

If $GP \leq 110$ M ACFM:

$$EA2 = 25.8\ RP \left(\frac{GP}{20}\right)^{0.5} \qquad \text{M\$}$$

If $GP > 110$ M ACFM:

$$EA2 = 119\ RP \left(\frac{GP}{3300}\right)^{0.5} \qquad \text{M\$}$$

If $S \leq 1000$ lbs/hr:

$$EA3 = 20.7 \left(\frac{S}{170}\right)^{0.5} + 14.7\ IF \left(\frac{S}{170}\right)^{0.6} \qquad \text{M\$}$$

$$ES = 42.1 \left(\frac{S}{170}\right)^{0.6} + 39.6 \left(\frac{S}{170}\right)^{0.7} + 9.5 \left(\frac{S}{170}\right)^{0.8} \qquad \text{M\$}$$

$$EP = 54.7 \left(\frac{S}{170}\right)^{0.5} + 28.2 \left(\frac{S}{170}\right)^{0.8} \qquad \text{M\$}$$

$$ER = 51.0 \left(\frac{S}{170}\right)^{0.7} + 26.2 \left(\frac{S}{170}\right)^{0.8} \qquad \text{M\$}$$

If $S > 1000$ lbs/hr:

TABLE 6.9 (CONTINUED)

$$EA3 = \left[\ 133 \left(\frac{S7}{7}\right)^{0.5} + 127\ IF \left(\frac{S7}{7}\right)^{0.6}\ \right] N7 \qquad \text{M\$}$$

$$ES = \left[\ 209 \left(\frac{S7}{7}\right)^{0.5} + 618 \left(\frac{S7}{7}\right)^{0.6} + 157 \left(\frac{S7}{7}\right)^{0.9}\ \right] N7 \qquad \text{M\$}$$

$$EP = \left[\ 525 \left(\frac{S28}{28}\right)^{0.5} + 380 \left(\frac{S28}{28}\right)^{0.6} + 86 \left(\frac{S28}{28}\right)^{0.7} + 306 \left(\frac{S28}{28}\right)^{0.8} + 519 \left(\frac{S28}{28}\right)^{0.9}\ \right] N28 \qquad \text{M\$}$$

$$ER = 998 \left(\frac{SF}{28}\right)^{0.5} + 287 \left(\frac{SF}{28}\right)^{0.6} + 683 \left(\frac{SF}{28}\right)^{0.9} \qquad \text{M\$}$$

where $S7 = \frac{S}{1000\ N7}$; $S28 = \frac{S}{1000\ N28}$; $SF = \frac{S}{1000}$

For the plant:

$$EA = EA1 + EA2 + EA3 \qquad \text{M\$}$$

$$E = EA + ES + EP + ER \qquad \text{M\$}$$

$$L = 0.224\ EA + 0.310\ ES + 0.433\ EP + 0.623\ ER \qquad \text{M\$}$$

$$M = 0.429\ EA + 0.742\ ES + 0.827\ EP + 0.772\ ER \qquad \text{M\$}$$

$$AL = 28.2\ CS \cdot LF \left(\frac{SF}{28}\right) \qquad \text{M\$/yr}$$

$$AN = 1460\ CN \cdot LF \left(\frac{SF}{28}\right) \qquad \text{M\$/yr}$$

$$AFA = 1.24\ CFA \cdot LF \cdot IF \left(\frac{GP}{3300}\right) \qquad \text{M\$/yr}$$

$$AE = \left[\ 154 \left(\frac{GP}{3300}\right) + 79 \left(\frac{SF}{28}\right)\ \right] CE \cdot LF \qquad \text{M\$/yr}$$

$$AH = 5430\ CH \cdot LF \left(\frac{SF}{28}\right) \qquad \text{M\$/yr}$$

$$ACW = \left[\ 856 \left(\frac{GP}{3300}\right) + 19{,}900 \left(\frac{SF}{28}\right)\ \right] CCW \cdot LF \qquad \text{M\$/yr}$$

$$AW = 64 \left(\frac{SF}{28}\right) CW \cdot LF \qquad \text{M\$/yr}$$

$$AF = 1{,}800 \left(\frac{GP}{3300}\right) CF \cdot LF \qquad \text{M\$/yr}$$

TABLE 6.9 (CONTINUED)

$$\mathrm{ASC} = 95.4 \left(\frac{\mathrm{SF}}{28}\right) \mathrm{VSC}\cdot\mathrm{LF} \qquad \text{M\$/yr}$$

$$\mathrm{APS} = 37.3 \left(\frac{\mathrm{SF}}{28}\right) \mathrm{VPS}\cdot\mathrm{LF} \qquad \text{M\$/yr}$$

$$\mathrm{ANR} = \mathrm{AS} + \mathrm{AN} + \mathrm{AFA} + \mathrm{AE} + \mathrm{AH} + \mathrm{ACW} + \mathrm{AW} + \mathrm{AF} - \mathrm{ASC} - \mathrm{APS} \qquad \text{M\$/yr}$$

$$\mathrm{BARC} = 1.15\ (\mathrm{E} + \mathrm{M}) + 1.43\ \mathrm{L}\cdot\mathrm{F} \qquad \text{M\$}$$

$$\mathrm{TPI} = 1.12\ (1.0 + \mathrm{CONTIN})\ \mathrm{BARC} \qquad \text{M\$}$$

$$\mathrm{AOC} = 0.078\ \mathrm{TPI} + 2.0\ \mathrm{TO}\cdot\mathrm{CO}\ (1.0 + \mathrm{F}) + \mathrm{ANR} \qquad \text{M\$/yr}$$

$$\mathrm{CRED} = \mathrm{ASC} + \mathrm{APS} \qquad \text{M\$/yr}$$

$$\mathrm{WKC} = 0.2\ (\mathrm{AOC} + \mathrm{CRED}) \qquad \text{M\$}$$

$$\mathrm{STC} = 0.2\ (\mathrm{AOC} + \mathrm{CRED}) \qquad \text{M\$}$$

$$\mathrm{TCR} = 1.135\ \mathrm{TPI} + \mathrm{WKC} \qquad \text{M\$}$$

$$\mathrm{TAC} = \frac{\mathrm{STC} + \mathrm{TCR} - 0.239\ \mathrm{WKC} - 0.291\ \mathrm{TPI}}{3.955} + \mathrm{AOC} \qquad \text{M\$/yr}$$

Note: See Appendix J for Explanation of Symbols

TABLE 6.10

SUMMARY OF STACK GAS SCRUBBING COSTS BY STATES
WET LIMESTONE PROCESS APPLIED TO INDUSTRIAL BOILER PLANTS

STATE	NO. OF PLANTS	CAPACITY (MMBTU/HR)	PRODUCTION (MMBTU/HR)	TCR (M$)	TAC (M$/YR)	TCR ($/MMBTU/YR)	TAC ($/MMBTU)
ALABAMA	5	9241.	5986.	67863.	21160.	0.84	0.40
ALASKA	0	0.	0.	0.	0.	0.0	0.0
ARIZONA	0	0.	0.	0.	0.	0.0	0.0
ARKANSAS	0	0.	0.	0.	0.	0.0	0.0
CALIFORNIA	1	60.	46.	1495.	412.	2.85	1.03
COLORADO	2	180.	54.	3265.	889.	2.07	1.88
CONNECTICUT	1	108.	54.	620.	179.	0.66	0.38
DELAWARE	5	1091.	752.	10205.	2971.	1.07	0.45
FLORIDA	0	0.	0.	0.	0.	0.0	0.0
GEORGIA	11	7073.	4336.	44711.	13335.	0.72	0.35
HAWAII	12	6370.	3986.	52523.	15341.	0.94	0.44
IDAHO	6	1240.	139.	19556.	5314.	1.80	4.35
ILLINOIS	0	0.	0.	0.	0.	0.0	0.0
INDIANA	60	22930.	11764.	287192.	82365.	1.43	0.80
IOWA	62	32478.	15343.	326503.	95923.	1.15	0.71
KANSAS	9	5647.	1762.	80035.	11742.	1.62	0.76
KENTUCKY	0	0.	0.	0.	0.	0.0	0.0
LOUISIANA	17	4691.	2145.	50566.	14464.	1.23	0.77
MAINE	0	0.	0.	0.	0.	0.0	0.0
MARYLAND	35	12585.	6364.	109632.	31599.	0.99	0.57
MASSACHUSETTS	0	0.	0.	0.	0.	0.0	0.0
MICHIGAN	89	16304.	5546.	220470.	61114.	1.54	1.26
MINNESOTA	52	24869.	11125.	280480.	81538.	1.29	0.84
MISSISSIPPI	32	8731.	3853.	119100.	33865.	1.56	1.00
MISSOURI	0	0.	0.	0.	0.	0.0	0.0
MONTANA	6	5194.	2402.	46018.	13532.	1.01	0.63
NEBRASKA	2	854.	341.	6541.	1883.	0.87	0.63
NEVADA	0	0.	0.	0.	0.	0.0	0.0
NEW HAMPSHIR	0	0.	0.	0.	0.	0.0	0.0
NEW JERSEY	22	4884.	722.	57272.	10218.	1.34	1.62
NEW MEXICO	5	597.	387.	15945.	4813.	3.05	1.42
NEW YORK	0	0.	0.	0.	0.	0.0	0.0
N. CAROLINA	0	0.	0.	0.	0.	0.0	0.0
NORTH DAKOTA	45	14706.	8110.	123662.	55737.	0.96	0.78
OHIO	2	491.	222.	6242.	1704.	1.45	0.88
OKLAHOMA	125	44695.	23548.	565232.	164537.	1.44	0.80
OREGON	0	0.	0.	0.	0.	0.0	0.0
PENNSYLVANIA	0	0.	0.	0.	0.	0.0	0.0
RHODE ISLAND	91	30418.	15717.	400610.	115323.	1.50	0.84
S. CAROLINA	22	3065.	1050.	52440.	14361.	1.95	1.56
SOUTH DAKOTA	18	7765.	4244.	52405.	15088.	0.77	0.41
TENNESSEE	1	85.	8.	1550.	413.	2.08	5.97
TEXAS	12	10865.	6748.	45924.	13590.	0.48	0.23
UTAH	0	0.	0.	0.	0.	0.0	0.0
VERMONT	2	810.	452.	7267.	2049.	1.02	0.52
VIRGINIA	7	492.	214.	9531.	2545.	2.21	1.36
WASHINGTON	31	13662.	8116.	130368.	37743.	1.09	0.53
W. VIRGINIA	5	4255.	1207.	16887.	5089.	0.45	0.48
WISCONSIN	0	0.	0.	0.	0.	0.0	0.0
WYOMING	55	12218.	6245.	132463.	38374.	1.24	0.70
D. C.	1	338.	169.	1862.	540.	0.63	0.37

TABLE 6.11

SUMMARY OF STACK GAS SCRUBBING COSTS BY STATES

WELLMAN/ALLIED PROCESS APPLIED TO INDUSTRIAL BOILER PLANTS

STATE	NO. OF PLANTS	CAPACITY (MMBTU/HR)	PRODUCTION (MMBTU/HR)	TCR (M$)	TAC (M$/YR)	TCR ($/MMBTU/YR)	TAC ($/MMBTU)
ALABAMA	5	4291.	5986.	73766.	24156.	0.41	0.46
ALASKA	0	0.	0.	0.	0.	0.0	0.0
ARIZONA	0	0.	0.	0.	0.	0.0	0.0
ARKANSAS	0	0.	0.	0.	0.	0.0	0.0
CALIFORNIA	1	60.	46.	1500.	371.	2.47	0.95
COLORADO	2	180.	54.	3444.	954.	2.18	2.03
CONNECTICUT	1	108.	54.	474.	158.	0.50	0.33
DELAWARE	3	1091.	752.	4428.	2461.	0.49	0.45
FLORIDA	0	0.	0.	0.	0.	0.0	0.0
GEORGIA	11	7073.	4536.	46486.	14822.	0.75	0.39
HAWAII	12	6370.	3586.	55869.	16534.	0.46	0.53
IDAHO	6	1240.	139.	16966.	4855.	1.56	3.97
ILLINOIS	0	0.	0.	0.	0.	0.0	0.0
INDIANA	60	22930.	11764.	318590.	95170.	1.59	0.92
IOWA	62	32478.	15343.	340366.	118831.	1.37	0.88
KANSAS	9	3097.	1762.	47022.	14075.	1.45	0.91
KENTUCKY	0	0.	0.	0.	0.	0.0	0.0
LOUISIANA	17	4691.	2145.	60500.	17905.	1.47	0.95
MAINE	0	0.	0.	0.	0.	0.0	0.0
MARYLAND	35	12585.	6369.	111456.	33835.	1.01	0.61
MASSACHUSETT	0	0.	0.	0.	0.	0.0	0.0
MICHIGAN	69	16304.	5546.	232671.	56733.	1.65	1.37
MINNESOTA	52	24889.	11125.	318776.	97174.	1.46	1.00
MISSISSIPPI	32	8751.	3853.	124813.	36856.	1.03	1.09
MISSOURI	0	0.	0.	0.	0.	0.0	0.0
MONTANA	8	5194.	2462.	53072.	16367.	1.17	0.76
NEBRASKA	2	859.	341.	7218.	2190.	0.96	0.73
NEVADA	0	0.	0.	0.	0.	0.0	0.0
NEW HAMPSHIR	0	0.	0.	0.	0.	0.0	0.0
NEW JERSEY	22	3184.	722.	38252.	10884.	1.37	1.72
NEW MEXICO	5	597.	287.	20418.	6477.	3.90	2.58
NEW YORK	0	0.	0.	0.	0.	0.0	0.0
N. CAROLINA	0	0.	0.	0.	0.	0.0	0.0
NORTH DAKOTA	45	14706.	8110.	151733.	39974.	1.02	0.56
OHIO	2	491.	222.	6749.	1970.	1.57	1.01
OKLAHOMA	123	49695.	235[illegible]8.	643183.	195246.	1.48	0.95
OREGON	0	0.	0.	0.	0.	0.0	0.0
PENNSYLVANIA	0	0.	0.	0.	0.	0.0	0.0
RHODE ISLAND	91	30418.	15717.	436145.	131141.	1.64	0.95
S. CAROLINA	22	3065.	1050.	55118.	14992.	1.98	1.03
SOUTH DAKOTA	18	7763.	4244.	50948.	15584.	0.75	0.42
TENNESSEE	1	66.	8.	1553.	423.	2.69	6.11
TEXAS	12	10883.	6748.	49814.	15512.	0.52	0.26
UTAH	0	0.	0.	0.	0.	0.0	0.0
VERMONT	2	810.	452.	6075.	1843.	0.88	0.47
VIRGINIA	7	492.	214.	8789.	2465.	2.04	1.32
WASHINGTON	31	13662.	8118.	135489.	41394.	1.13	0.58
W. VIRGINIA	5	4255.	1207.	17714.	5871.	0.48	0.56
WISCONSIN	0	0.	0.	0.	0.	0.0	0.0
WYOMING	35	12218.	6295.	151613.	45539.	1.42	0.83
D. C.	1	338.	169.	2088.	654.	0.71	0.44

TABLE 6.12

COST SUMMARY FOR PACKAGED AND FIELD ERECTED
WET LIMESTONE SCRUBBING UNIT
(50 MM Btu/hr Industrial Boiler)

		(End of 74)	
Total Capital Required TCR,M$	Symbol	Field Erected	Packaged Unit
Major Equipment			
Chemical Process	EC	781	402
Solid Handling	ES	173	113
	E	954	515
Field Labor			
Chemical Process	LC	640	280
Solid Handling	LS	16	66
	L	656	346
Other Materials			
Chemical Process	MC	305	233
Solid Handling	MS	31	114
	M	336	347
Settling Pond	P	500	500
Bare Cost of Plant	BARC	3350	2679
Plant Investment	TPI	3752	3000
Interest During Construction	IDC	507	405
Working Capital	WKC	105	88
Total Capital Required	TCR	4364	3493
Total Capital Required** $/MM Btu/yr.		9.96	7.97

		(End of 74)	
Total Annual Production Cost TAC, M$/yr.	Symbol	Field Erected	Packaged Unit
Raw Materials and Utilities*			
Limestone	AL	15.5	15.5
Ammonia	AA	.2	.2
Process Water	AW	.6	.6
Fuel Oil	AF	15.7	15.7
Electricity	AE	3.0	3.0
	ANR		35
Number of Operators	TO	5	5
Operating Labor & Superv.	AOL	118	118
Main. Labor & Superv.	AML	68	54
Plant Supplies & Replmts.	APS	75	60
Admin. & Overhead	AOH	130	120
Direct & Indirect Cost		426	387
Local Taxes and Ins.	ATI	101	54
Net Annual Opr. Cost	AOC	527	441
Start-up Cost	STC	105	88
Depreciation, Return on Investment, Federal Tax		743	592
Total Annual Production Cost	TAC	1375	1121
Total Annual Production Cost $/MM Btu		3.94	3.21

* Based on a load factor of 80%

** Based on a yearly capacity of 50x8760=430,000 MM Btu/yr.

FIGURE 6.1

AVERAGE TOTAL CAPITAL REQUIREMENT FOR INSTALLING STACK GAS SCRUBBING IN EXISTING POWER PLANTS (MM$)

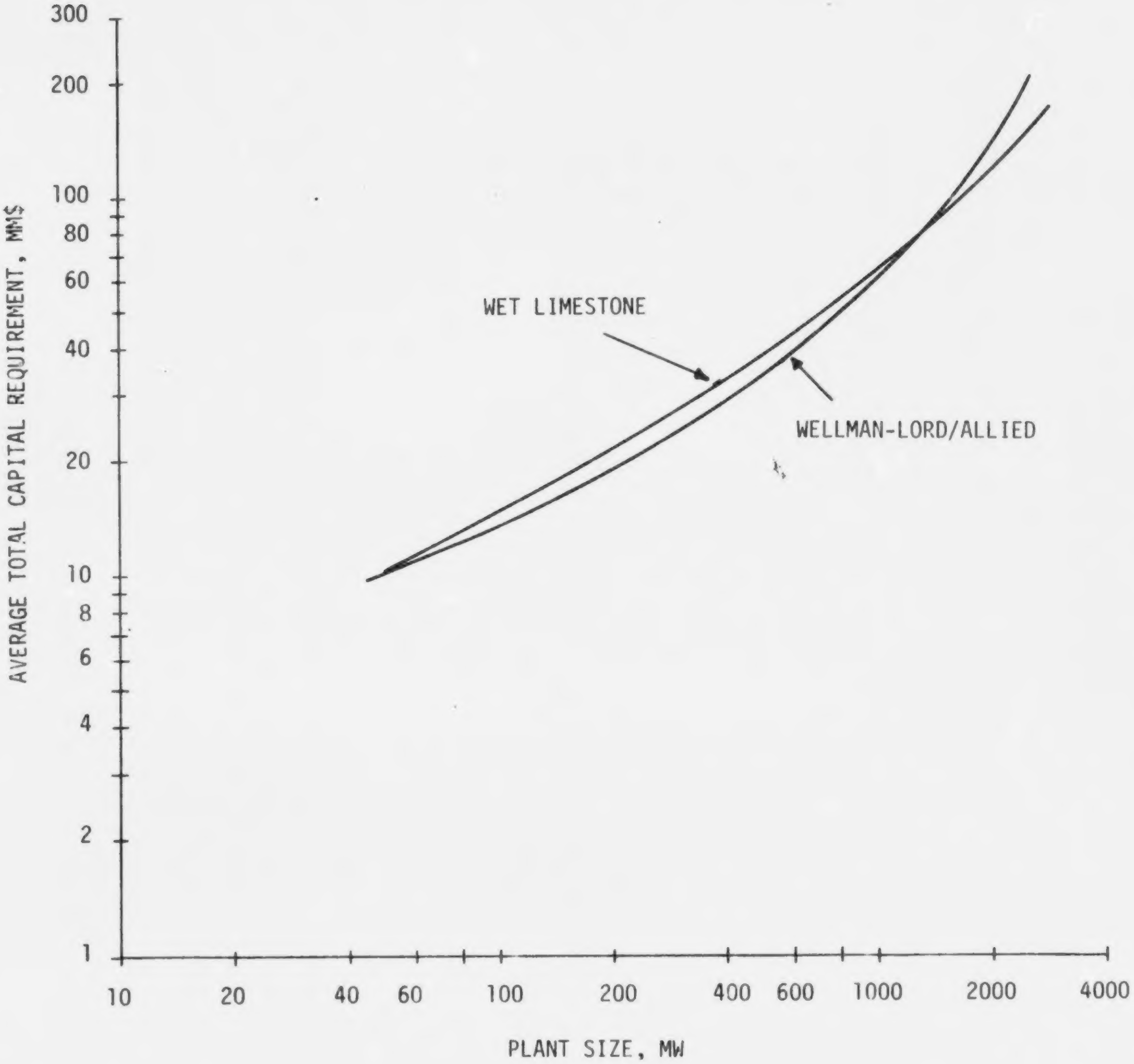


FIGURE 6.2
AVERAGE TOTAL CAPITAL REQUIREMENT FOR
INSTALLING STACK GAS SCRUBBING IN
EXISTING POWER PLANTS
($/KW)

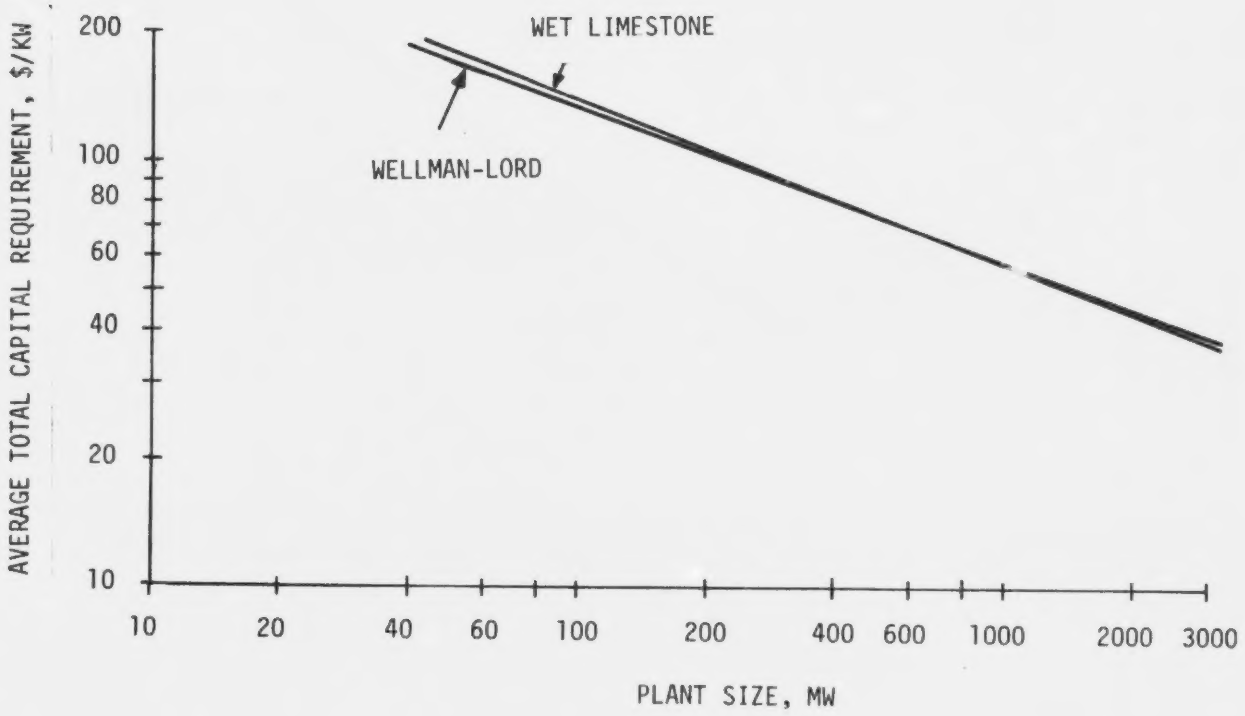


FIGURE 6.3
AVERAGE ANNUAL PRODUCTION COST OF STACK
GAS SCRUBBING IN EXISTING POWER PLANTS

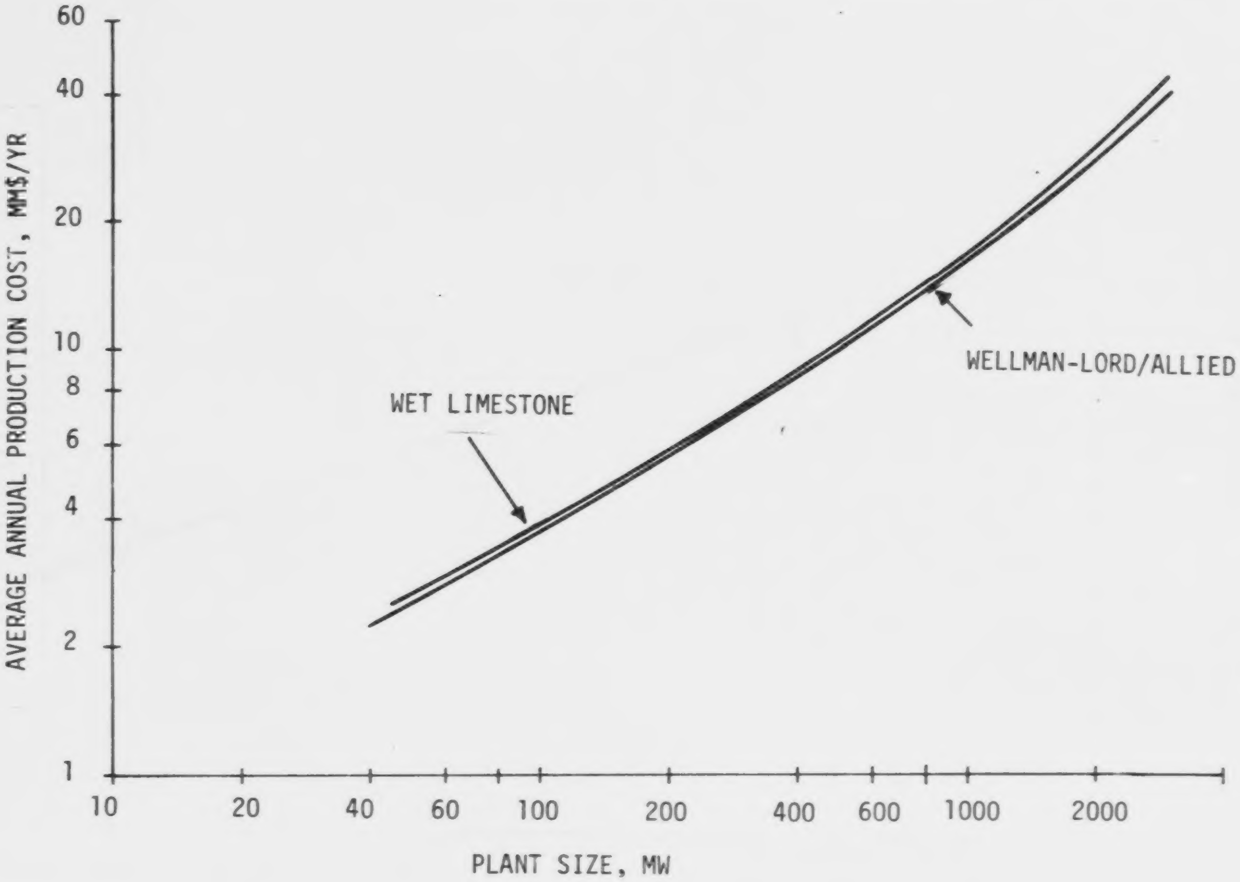


FIGURE 6.4
INCREMENTAL OPERATING COST OF STACK GAS
SCRUBBING IN EXISTING POWER PLANTS

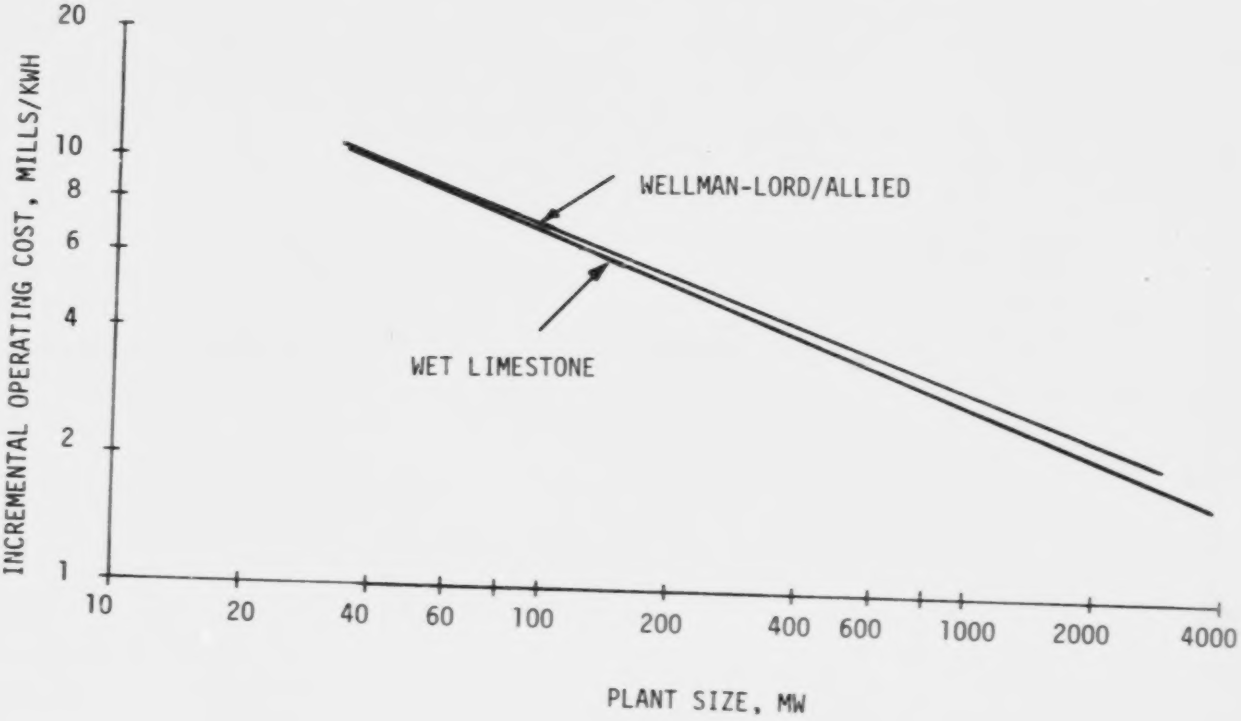


FIGURE 6.5

MAXIMUM TOTAL CAPITAL REQUIREMENT FOR INSTALLING STACK GAS SCRUBBING IN EXISTING POWER PLANTS

($/KW)

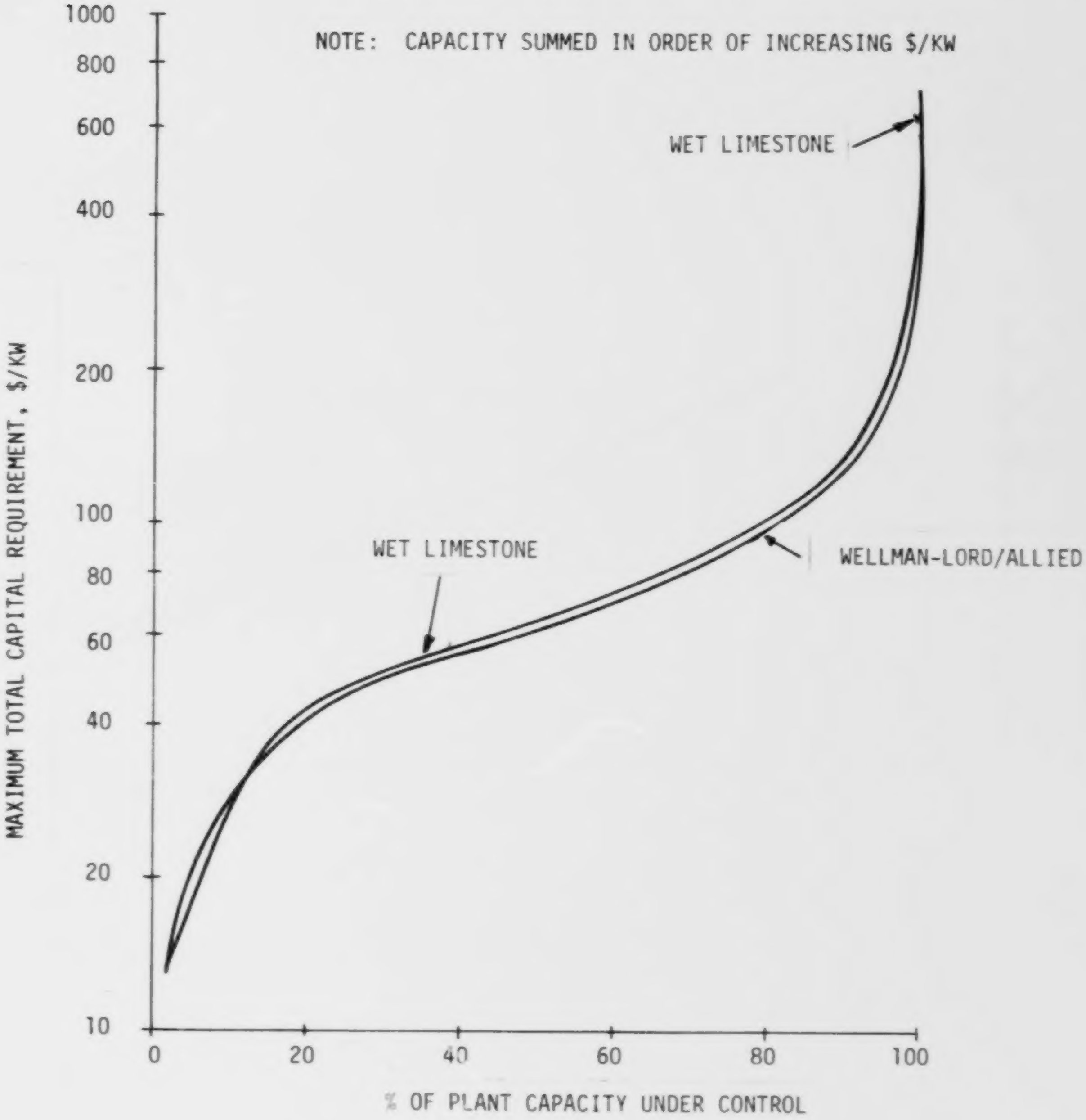


FIGURE 6.6

MAXIMUM INCREMENTAL OPERATING COST OF STACK GAS SCRUBBING IN EXISTING POWER PLANTS (MILLS/KWH)

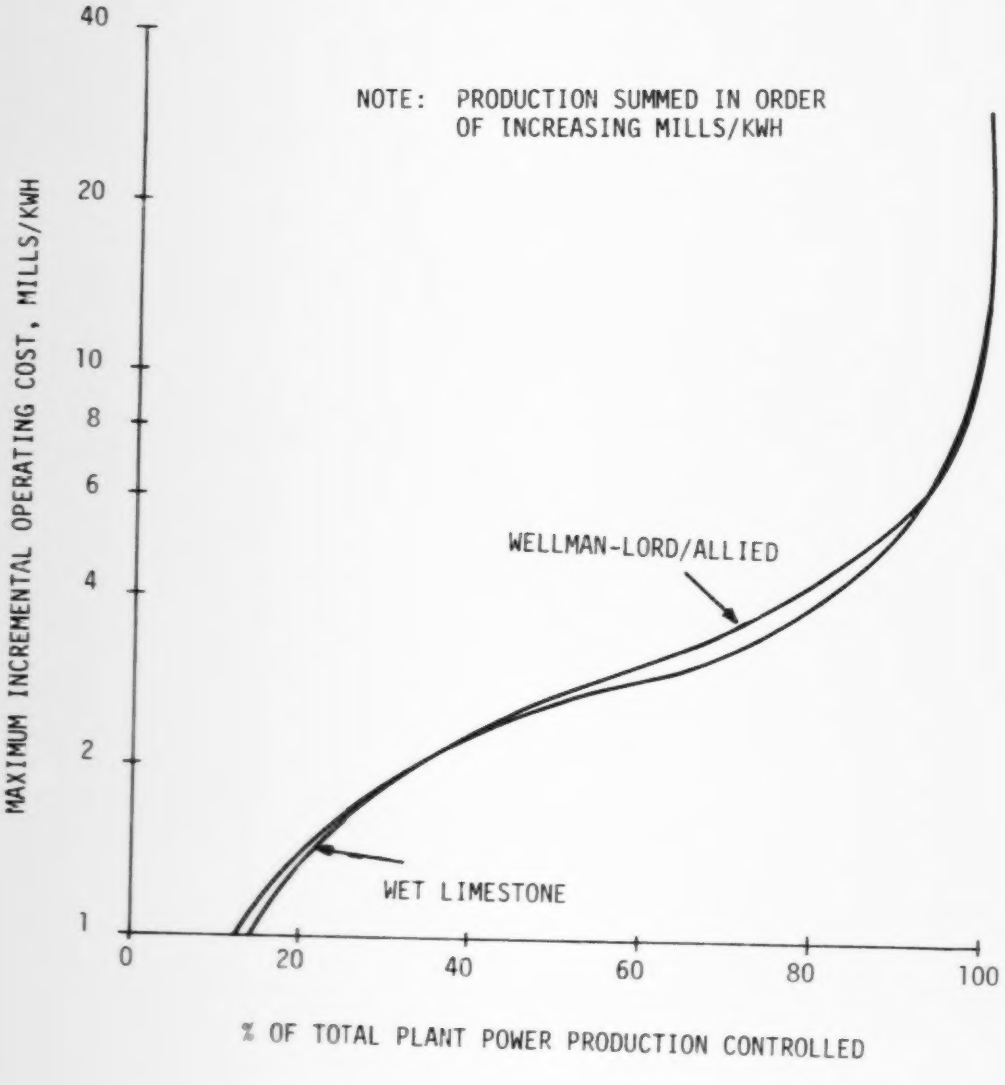


FIGURE 6.7
CUMULATIVE TOTAL CAPITAL REQUIREMENT
FOR INSTALLING STACK GAS SCRUBBING IN
EXISTING POWER PLANTS
(SUMMATION IN ORDER OF INCREASING $/KW)

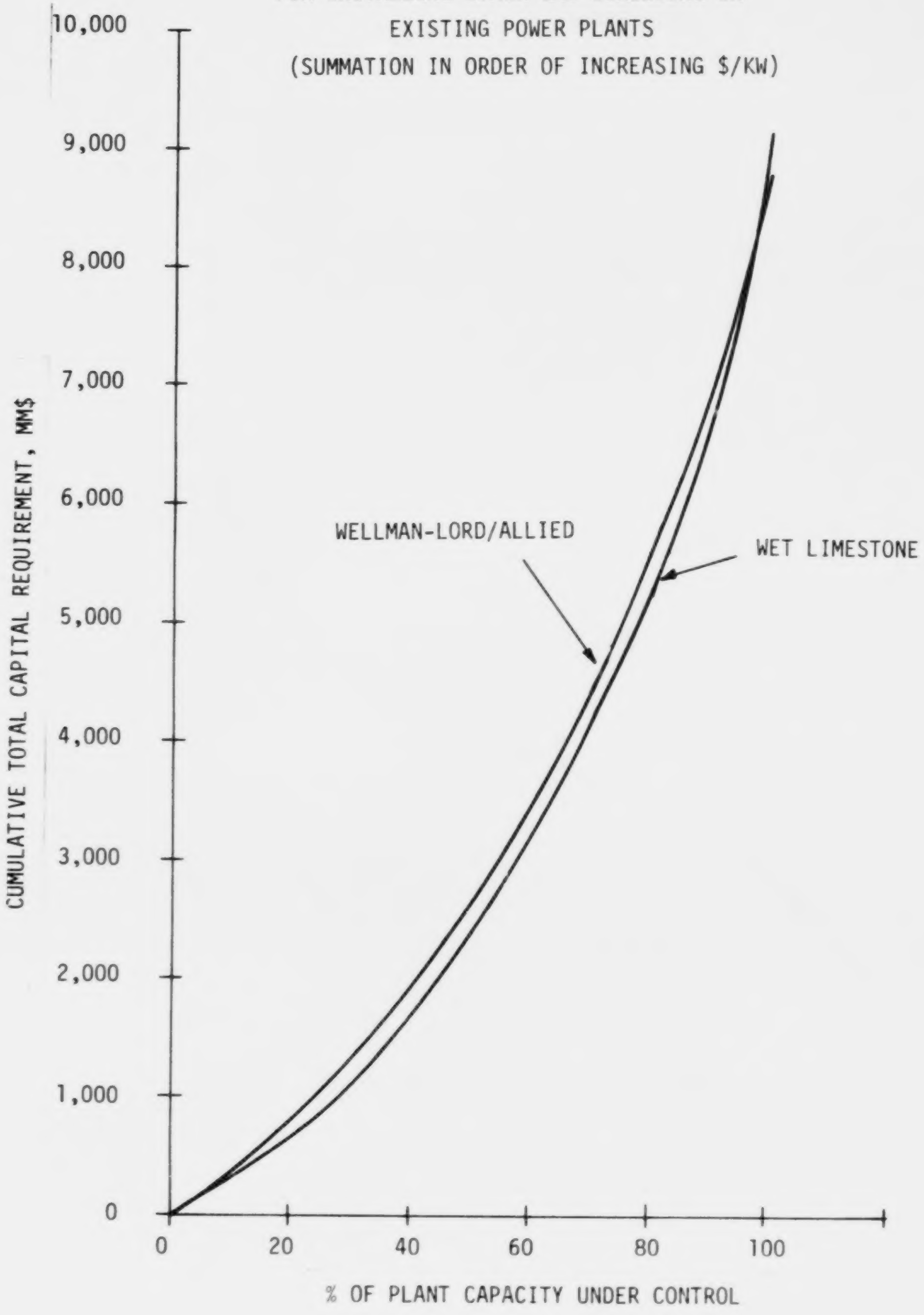


FIGURE 6.8
CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR INSTALLING STACK GAS SCRUBBING IN EXISTING POWER PLANTS
(SUMMATION IN ORDER OF DECREASING PLANT SIZE)

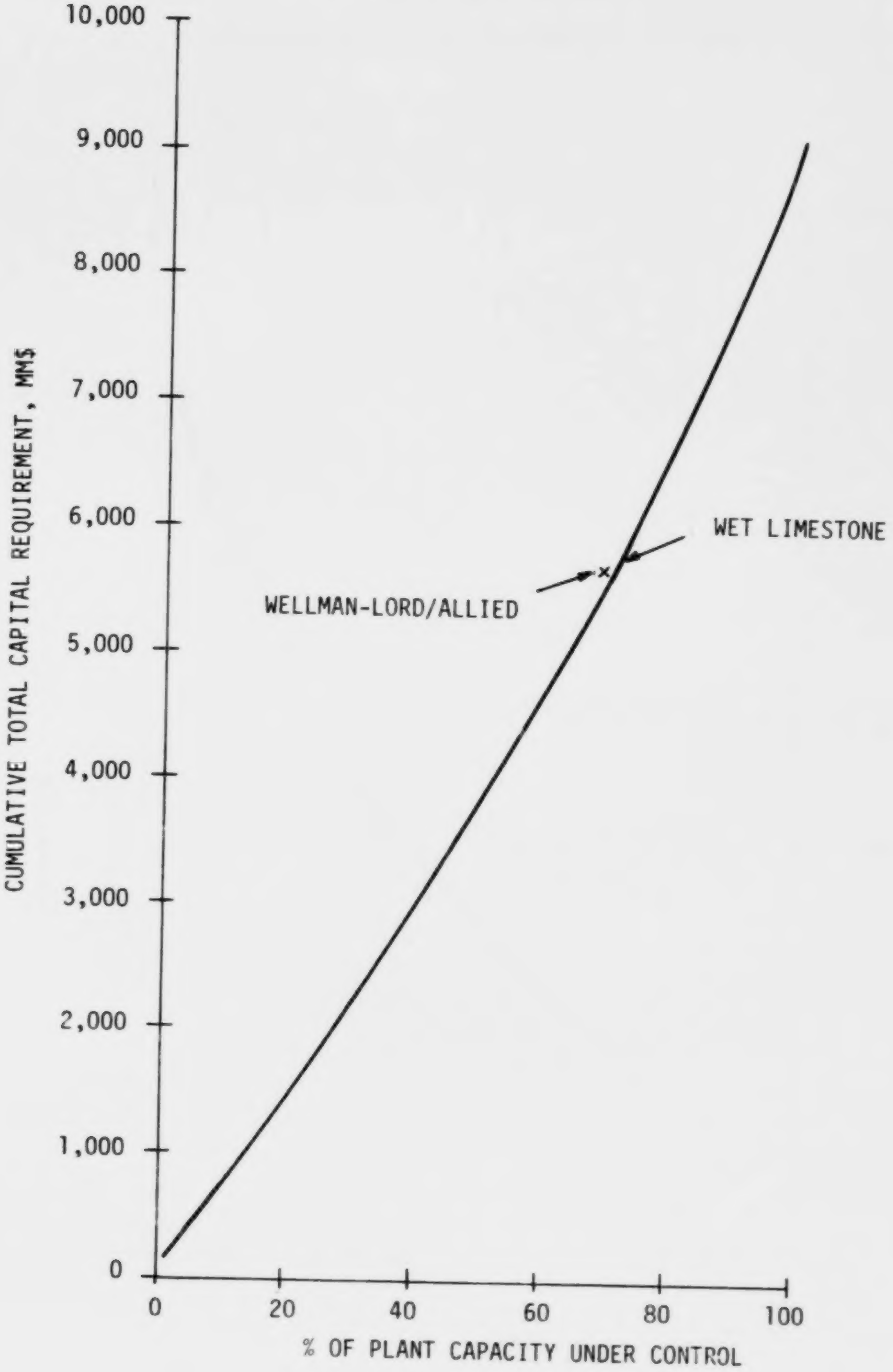


FIGURE 6.9

CUMULATIVE ANNUAL PRODUCTION COST OF
STACK GAS SCRUBBING IN
EXISTING POWER PLANTS
(SUMMATION IN ORDER OF INCREASING MILLS/KWH)

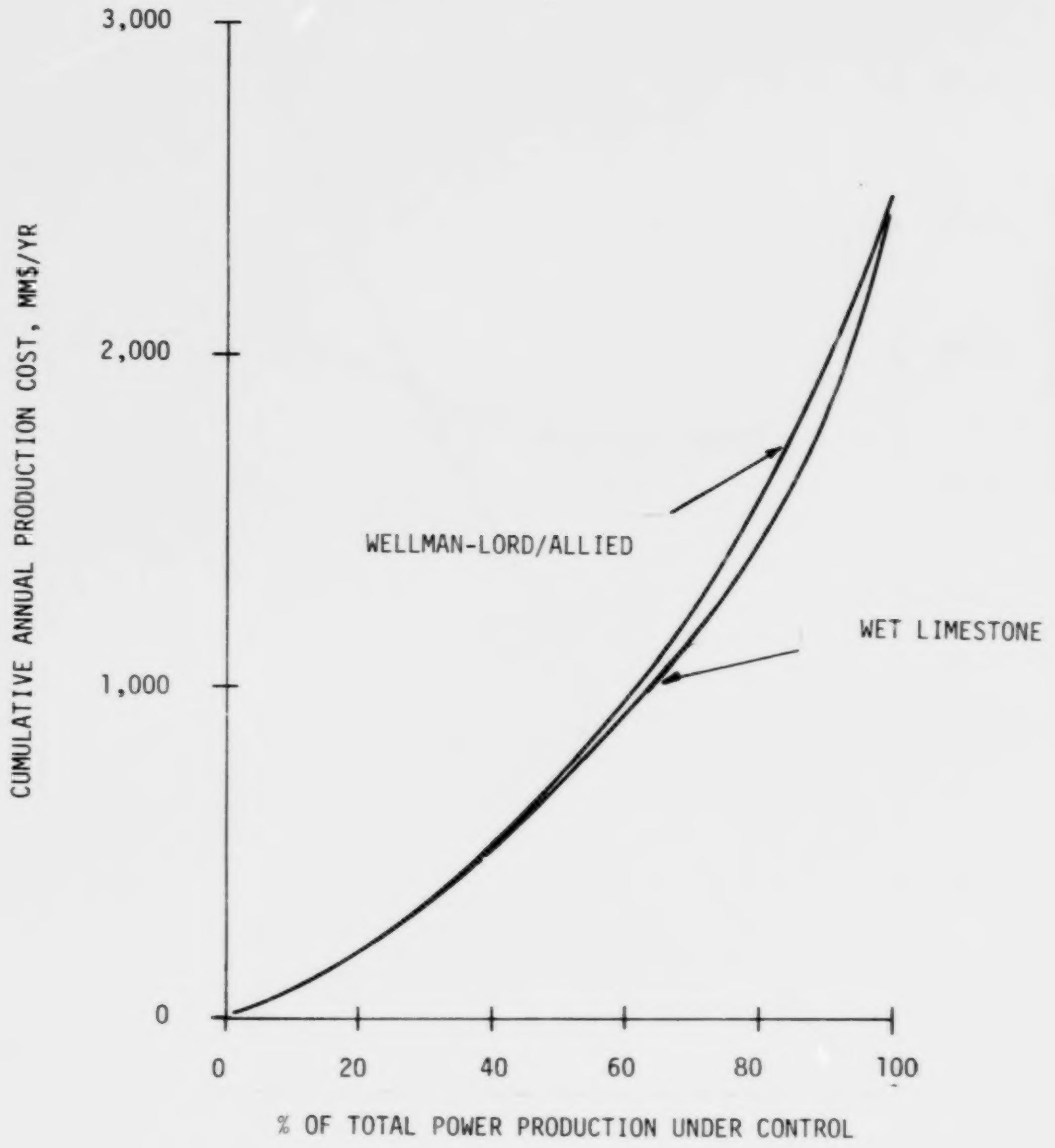


FIGURE 6.10
CUMULATIVE ANNUAL PRODUCTION COST OF STACK GAS SCRUBBING IN EXISTING POWER PLANTS
(SUMMATION IN ORDER OF DECREASING PLANT POWER PRODUCTION)

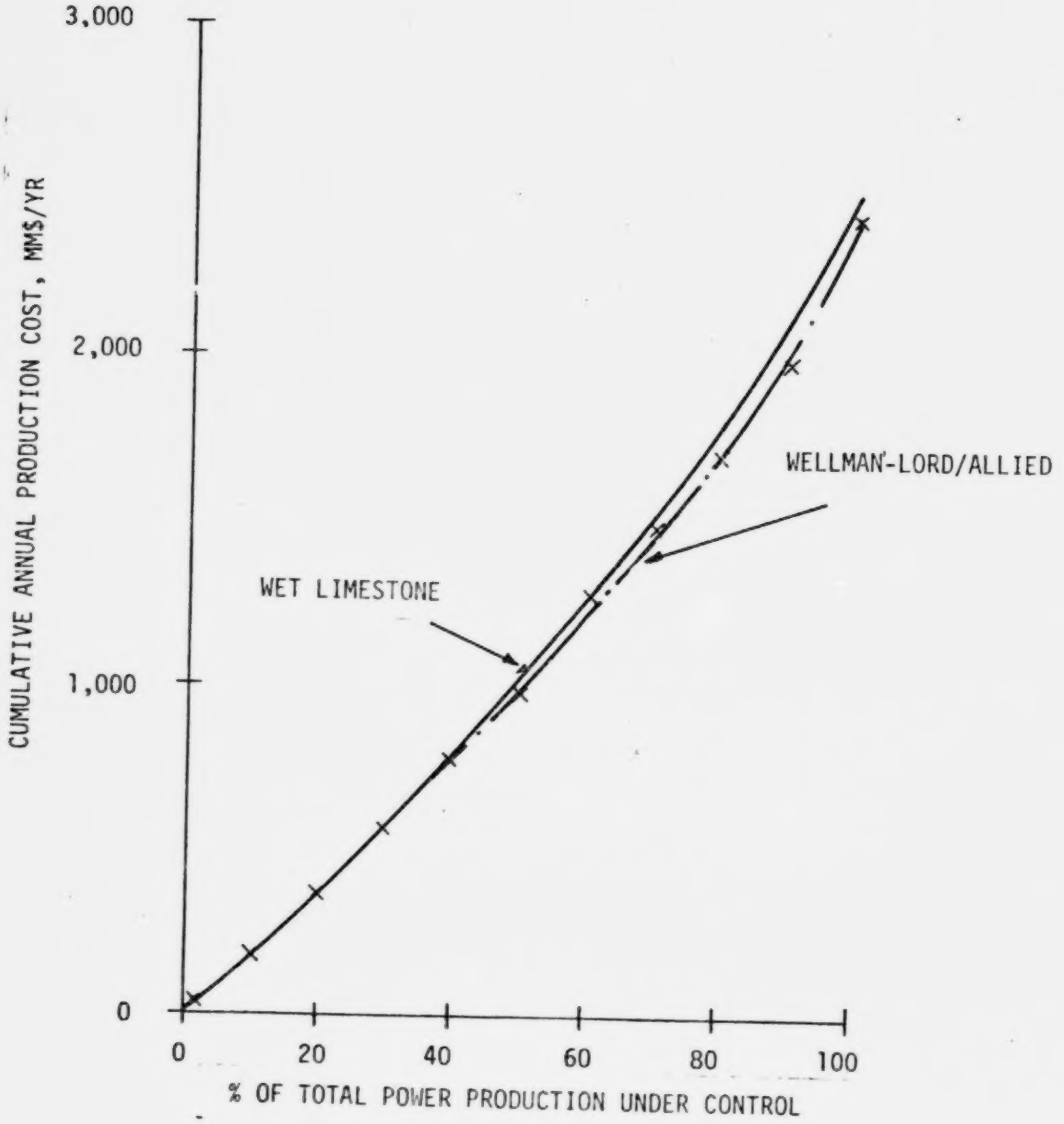


FIGURE 6.11

CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR REDUCING SULFUR EMISSIONS FROM EXISTING POWER PLANTS

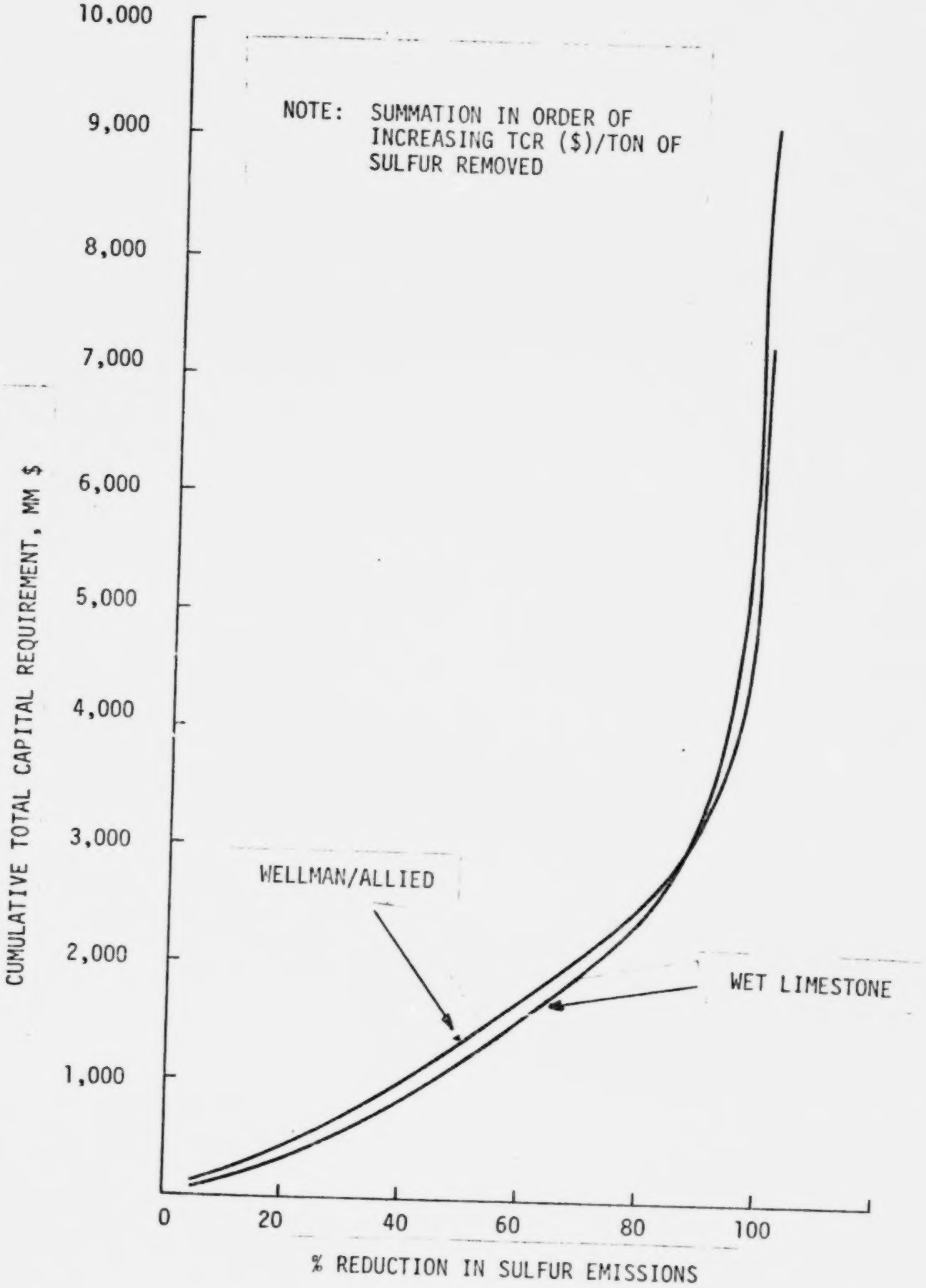


FIGURE 6.12

CUMULATIVE ANNUAL PRODUCTION COST OF REDUCING SULFUR EMISSIONS FROM EXISTING POWER PLANTS

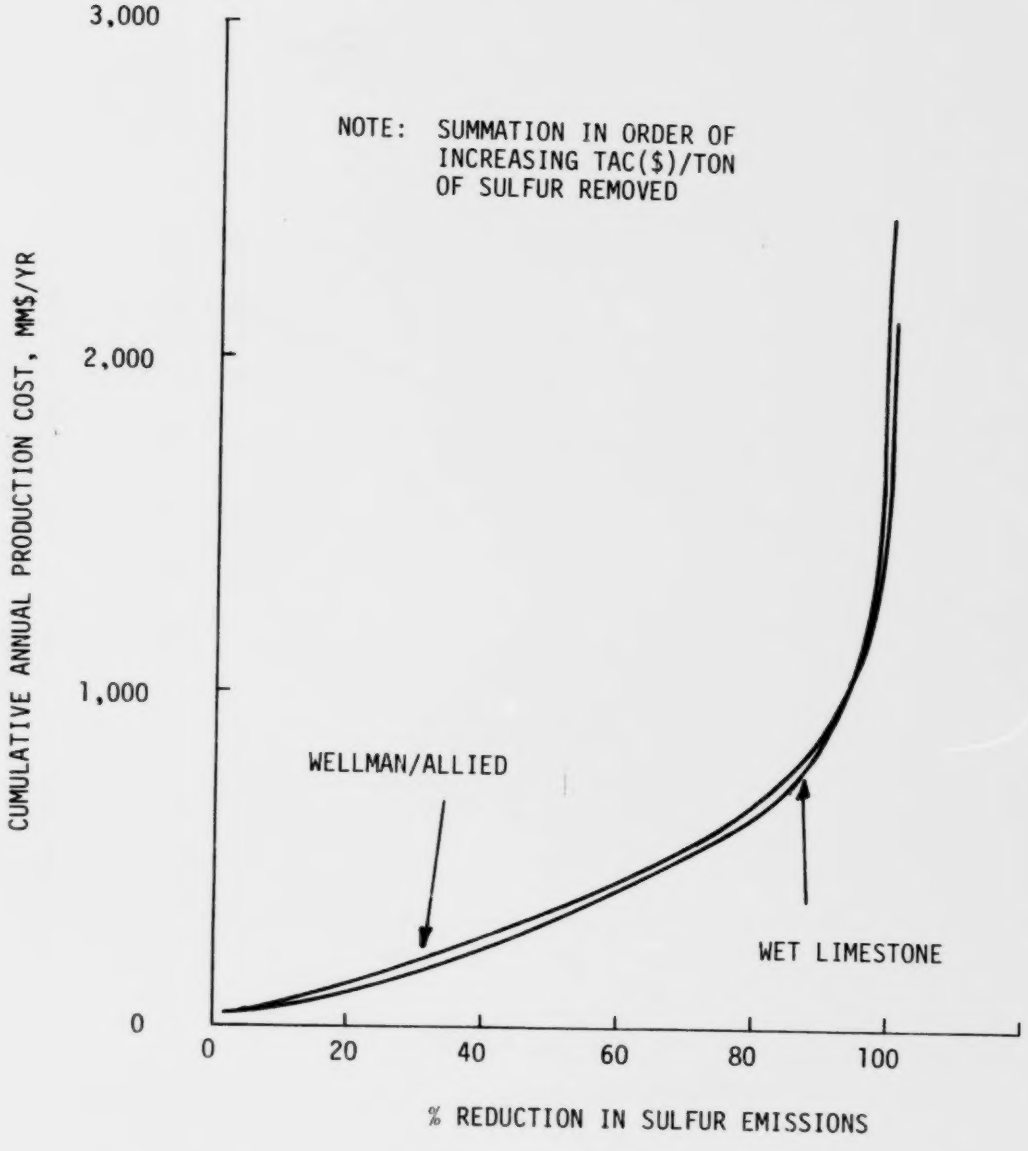
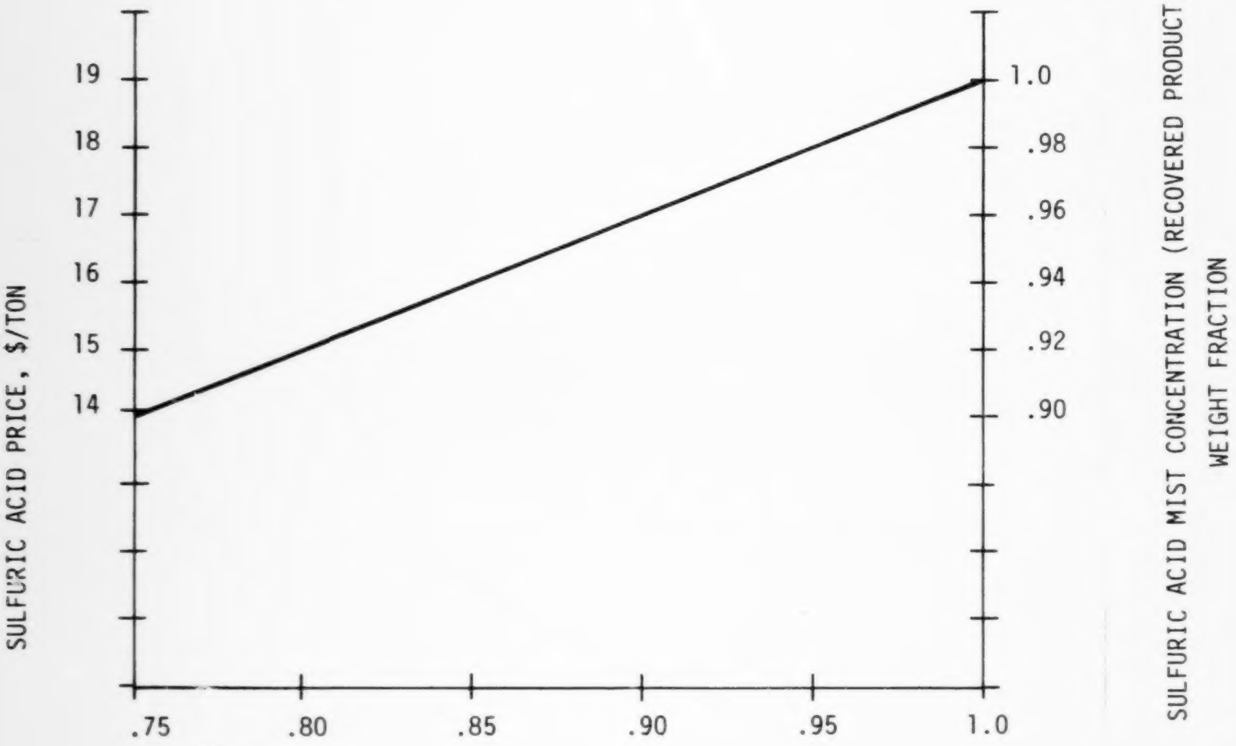


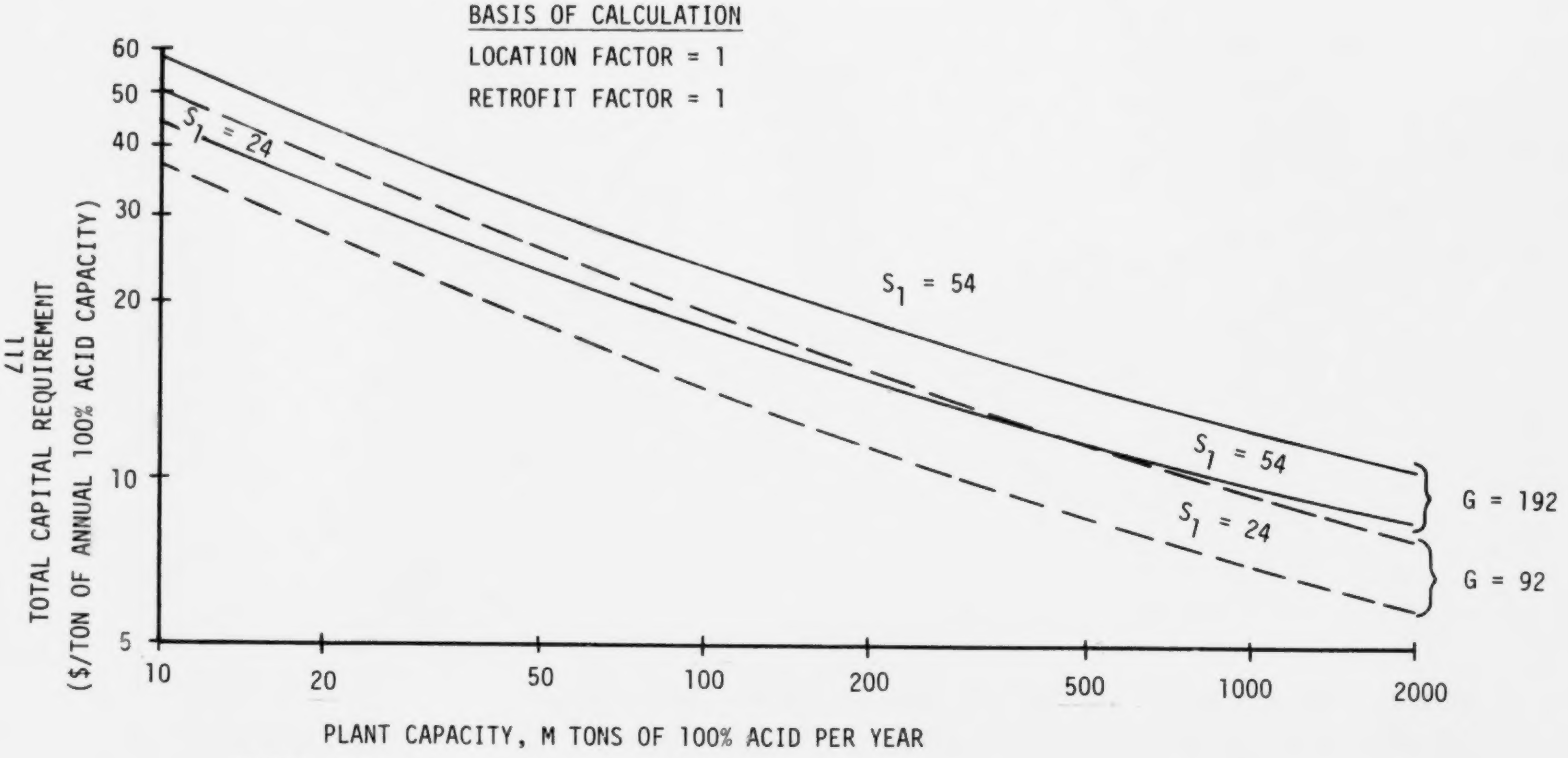
FIGURE 6.13
EFFECT OF ACID CONCENTRATION
ON SULFURIC ACID PRICE



SULFURIC ACID CONCENTRATION (PLANT PRODUCT)
WEIGHT FRACTION

FIGURE 6.14

EFFECT OF PLANT PARAMETERS ON TOTAL CAPITAL REQUIREMENT
WELLMAN-LORD PROCESS APPLIED TO SULFURIC ACID PLANTS



NOMENCLATURE

G = GAS DISCHARGE, MACF PER TON OF 100% ACID PRODUCED

S_1 = SO_2 CONTENT (AS SULFUR), LBS. PER TON OF 100% ACID PRODUCED

FIGURE 6.15

EFFECT OF PLANT PARAMETERS ON PRODUCTION COSTS—I

WELLMAN-LORD PROCESS APPLIED TO SULFURIC ACID PLANTS

BASIS OF CALCULATION

LOCATION FACTOR = 1

RETROFIT FACTOR = 1

S_2 = 14

NOMENCLATURE

G = GAS DISCHARGE, MACF PER TON OF 100% ACID PRODUCED

S_1 = SO_2 CONTENT (AS SULFUR), LBS. PER TON OF 100% ACID PRODUCED

S_2 = MIST CONTENT (AS SULFUR), LBS. PER TON OF 100% ACID PRODUCED

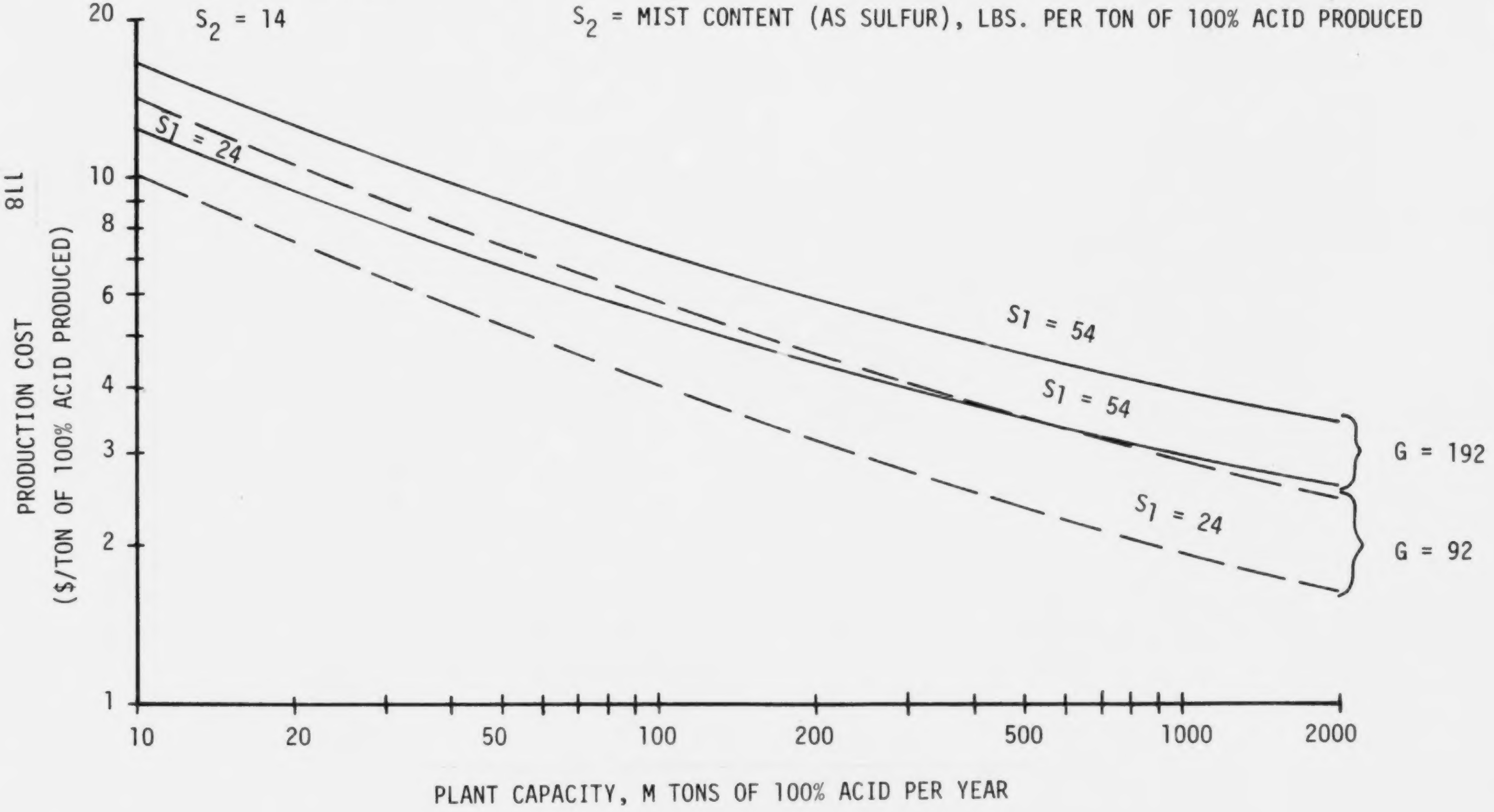
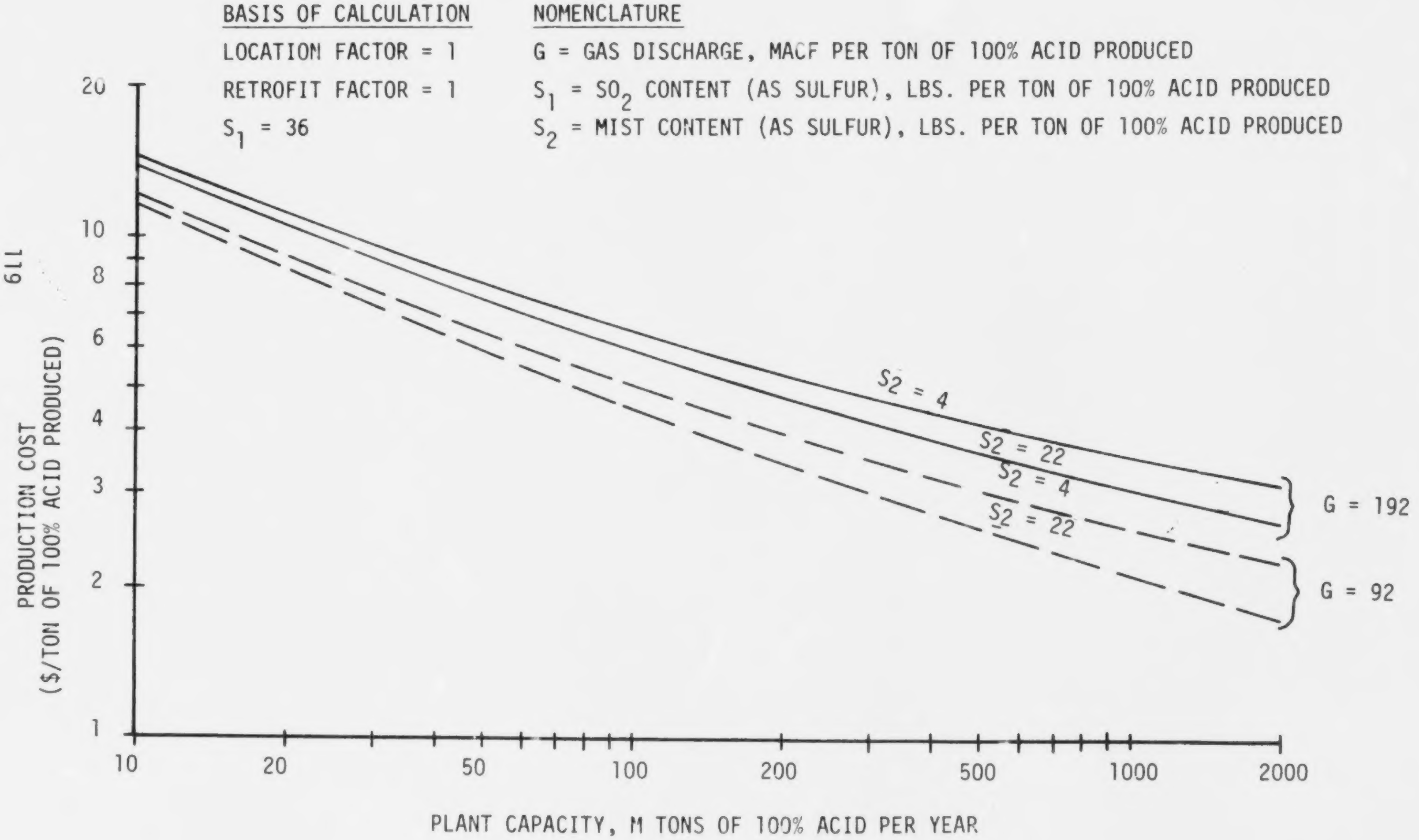


FIGURE 6.16

EFFECT OF PLANT PARAMETERS ON PRODUCTION COSTS - II
WELLMAN-LORD PROCESS APPLIED TO SULFURIC ACID PLANTS



BASIS OF CALCULATION

LOCATION FACTOR = 1
RETROFIT FACTOR = 1
S_1 = 36

NOMENCLATURE

G = GAS DISCHARGE, MACF PER TON OF 100% ACID PRODUCED
S_1 = SO_2 CONTENT (AS SULFUR), LBS. PER TON OF 100% ACID PRODUCED
S_2 = MIST CONTENT (AS SULFUR), LBS. PER TON OF 100% ACID PRODUCED

FIGURE 6.7
AVERAGE TOTAL CAPITAL REQUIREMENT FOR
INSTALLING WELLMAN-LORD STACK GAS SCRUBBING
IN EXISTING SULFURIC ACID PLANTS
(MM$)

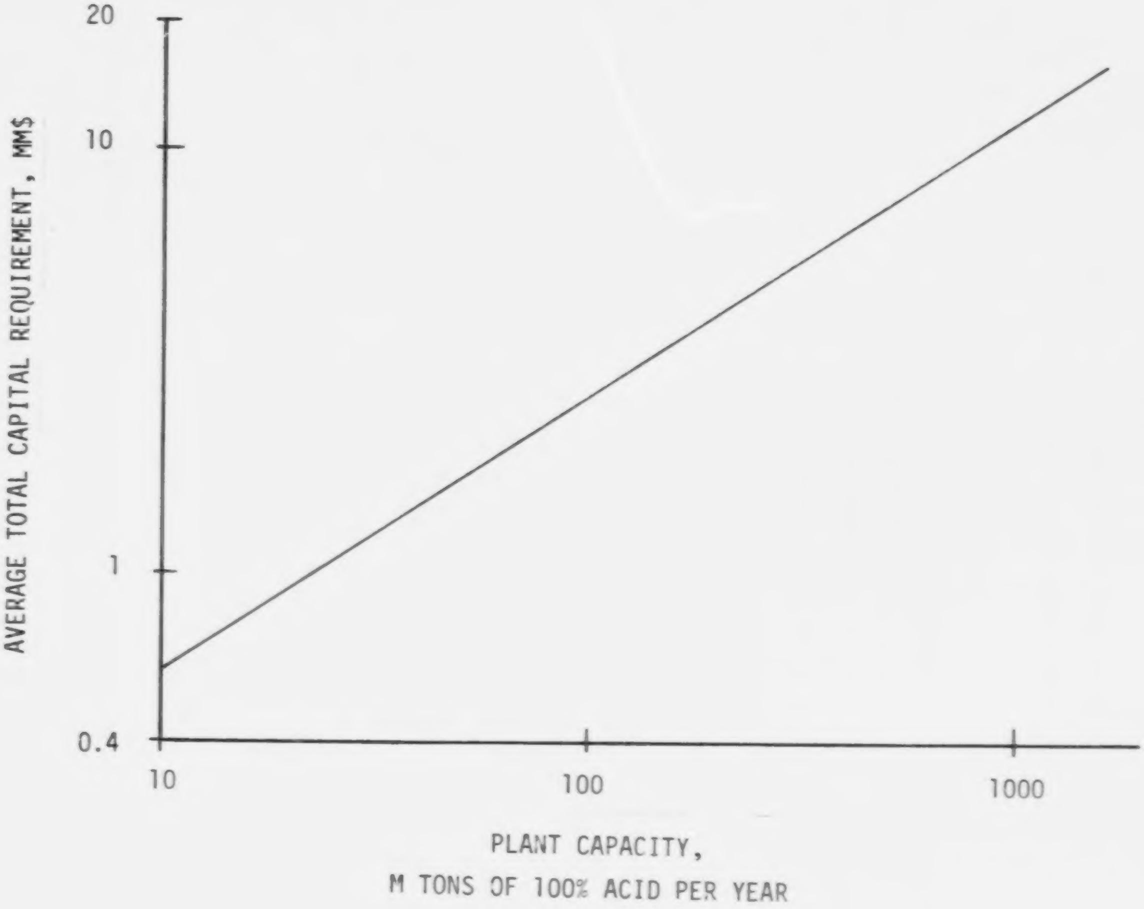


FIGURE 6.18

AVERAGE TOTAL CAPITAL REQUIREMENT FOR INSTALLING
WELLMAN-LORD STACK GAS SCRUBBING IN EXISTING SULFURIC ACID PLANTS
($/TON OF ANNUAL 100% ACID CAPACITY)

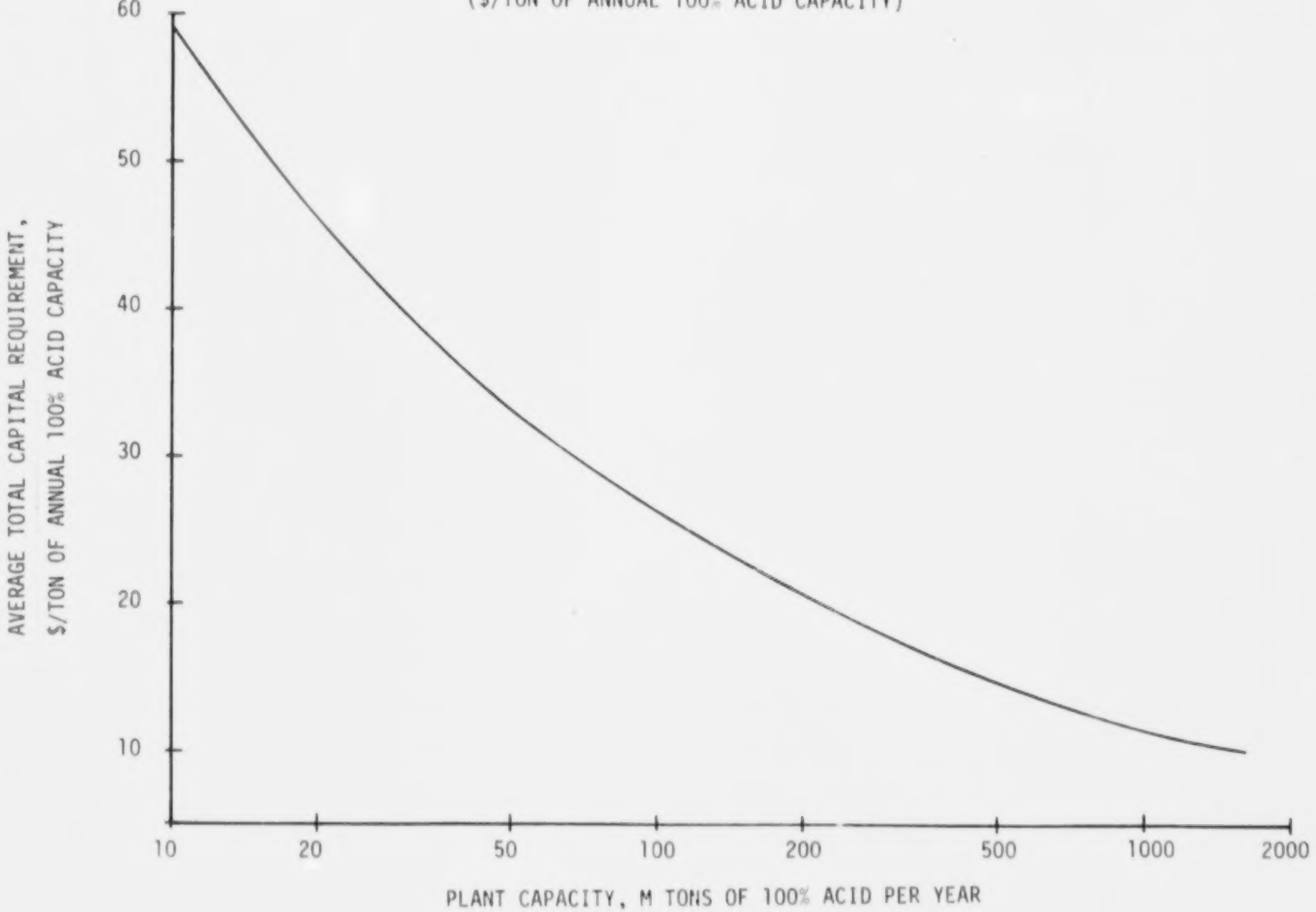


FIGURE 6.19

INCREMENTAL OPERATING COST OF WELLMAN-LORD STACK GAS SCRUBBING IN EXISTING SULFURIC ACID PLANTS

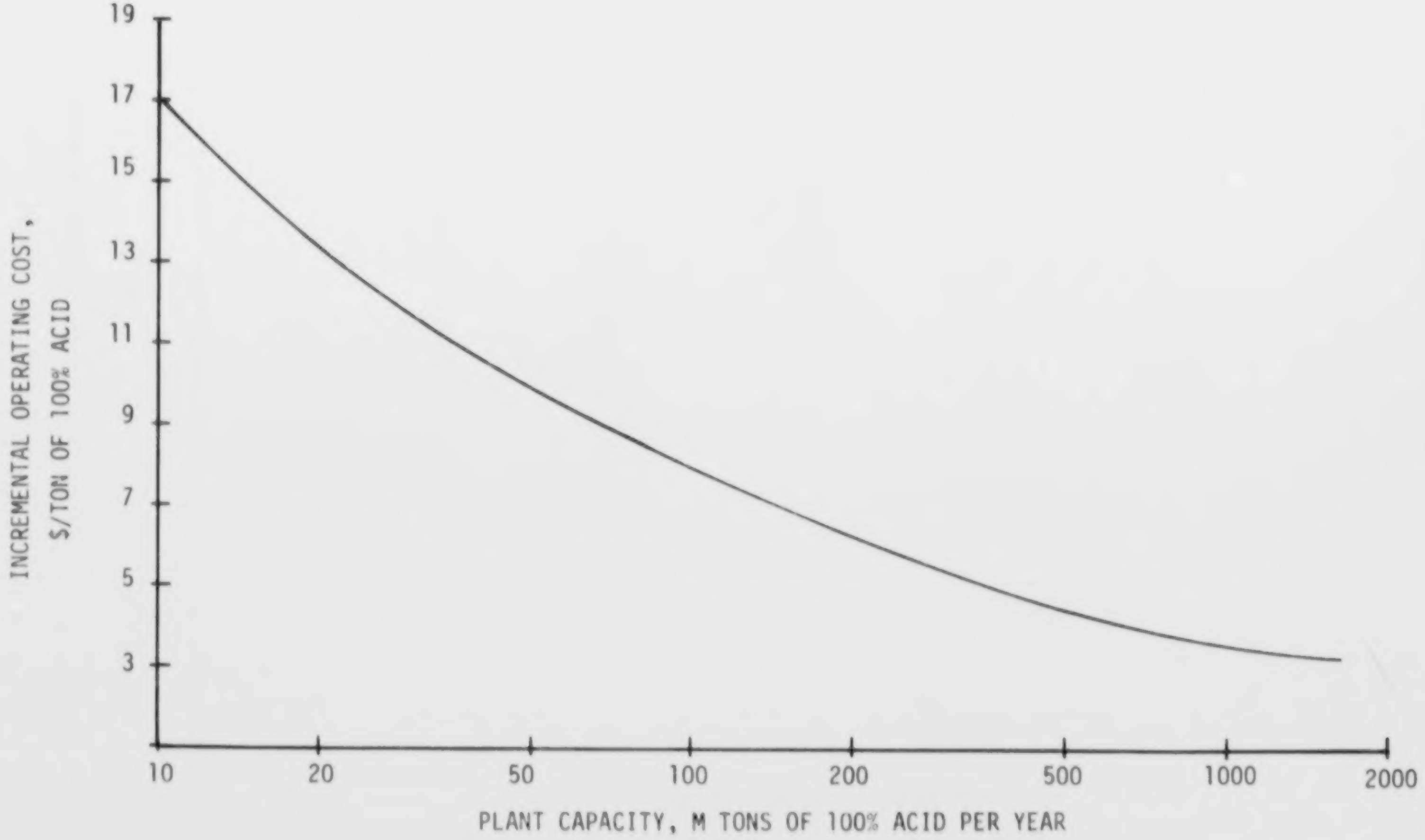


FIGURE 6.20

MAXIMUM TOTAL CAPITAL REQUIREMENT FOR INSTALLING WELLMAN-LORD STACK GAS SCRUBBING IN EXISTING SULFURIC ACID PLANTS

($/TON OF ANNUAL 100% ACID CAPACITY)

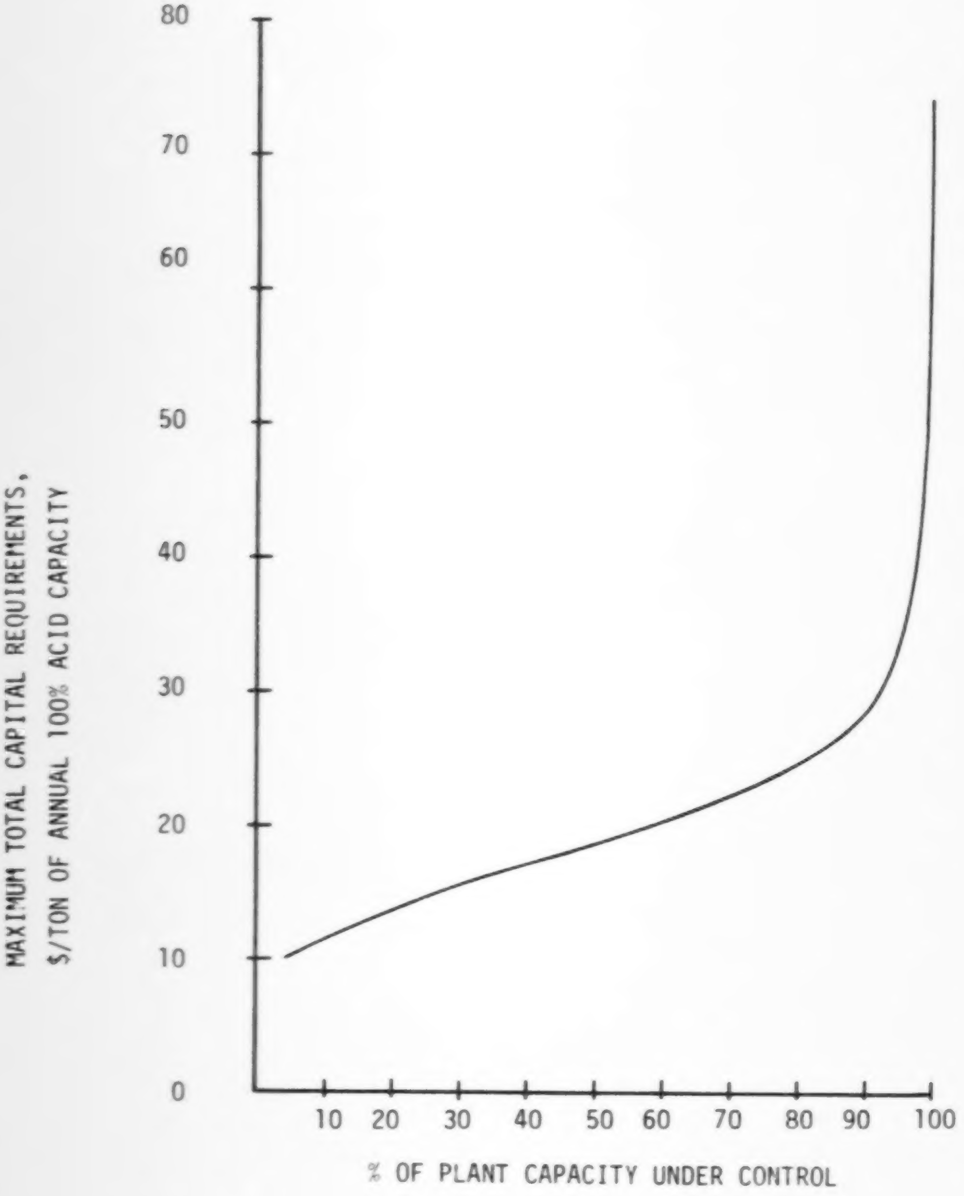
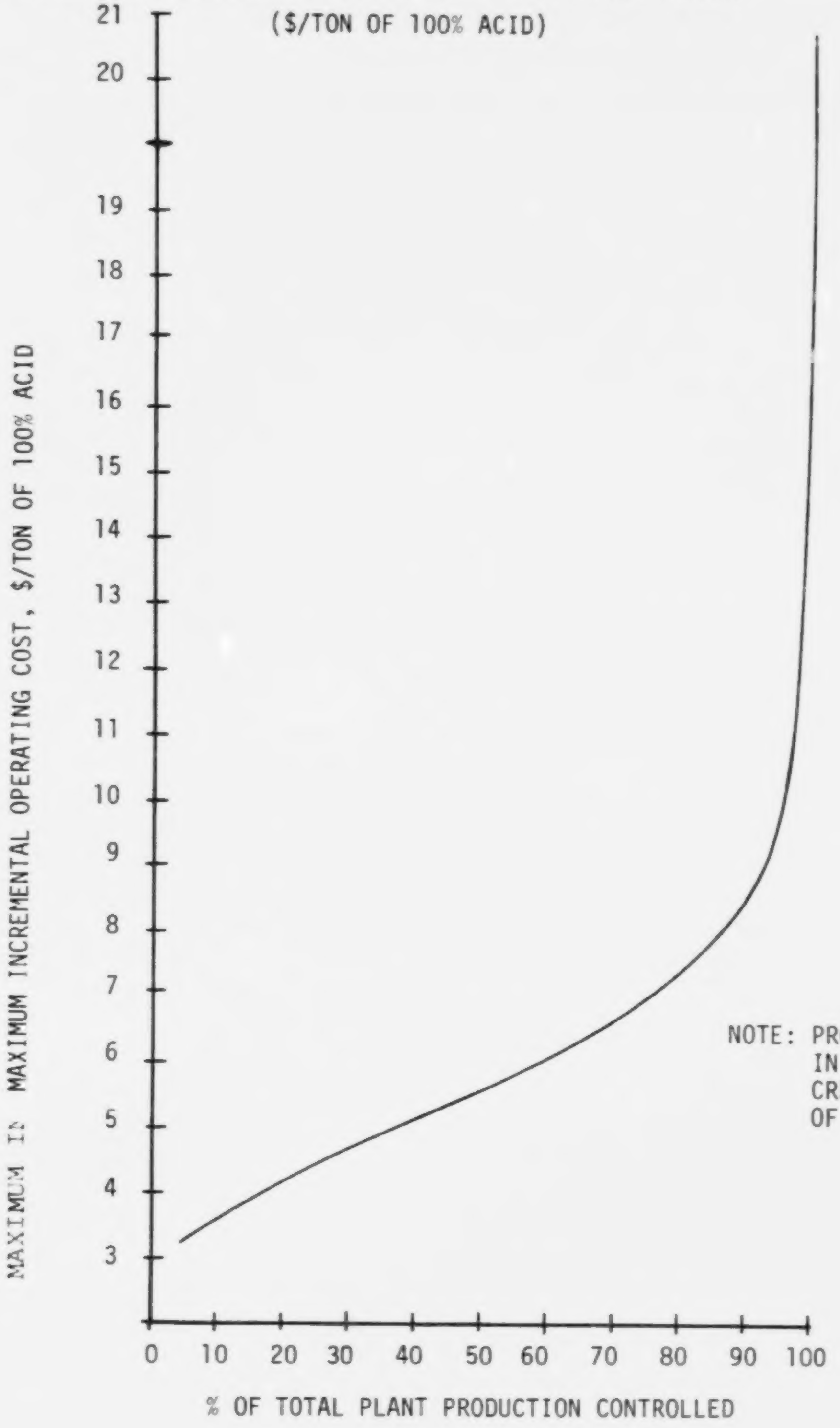


FIGURE 6.21

MAXIMUM INCREMENTAL OPERATING COST OF WELLMAN-LORD STACK GAS SCRUBBING IN EXISTING SULFURIC ACID PLANTS

($/TON OF 100% ACID)



NOTE: PRODUCTION SUMMED IN ORDER OF INCREASING $/TON OF ACID

FIGURE 6.22
CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR INSTALLING WELLMAN-LORD STACK GAS SCRUBBING IN EXISTING SULFURIC ACID PLANTS

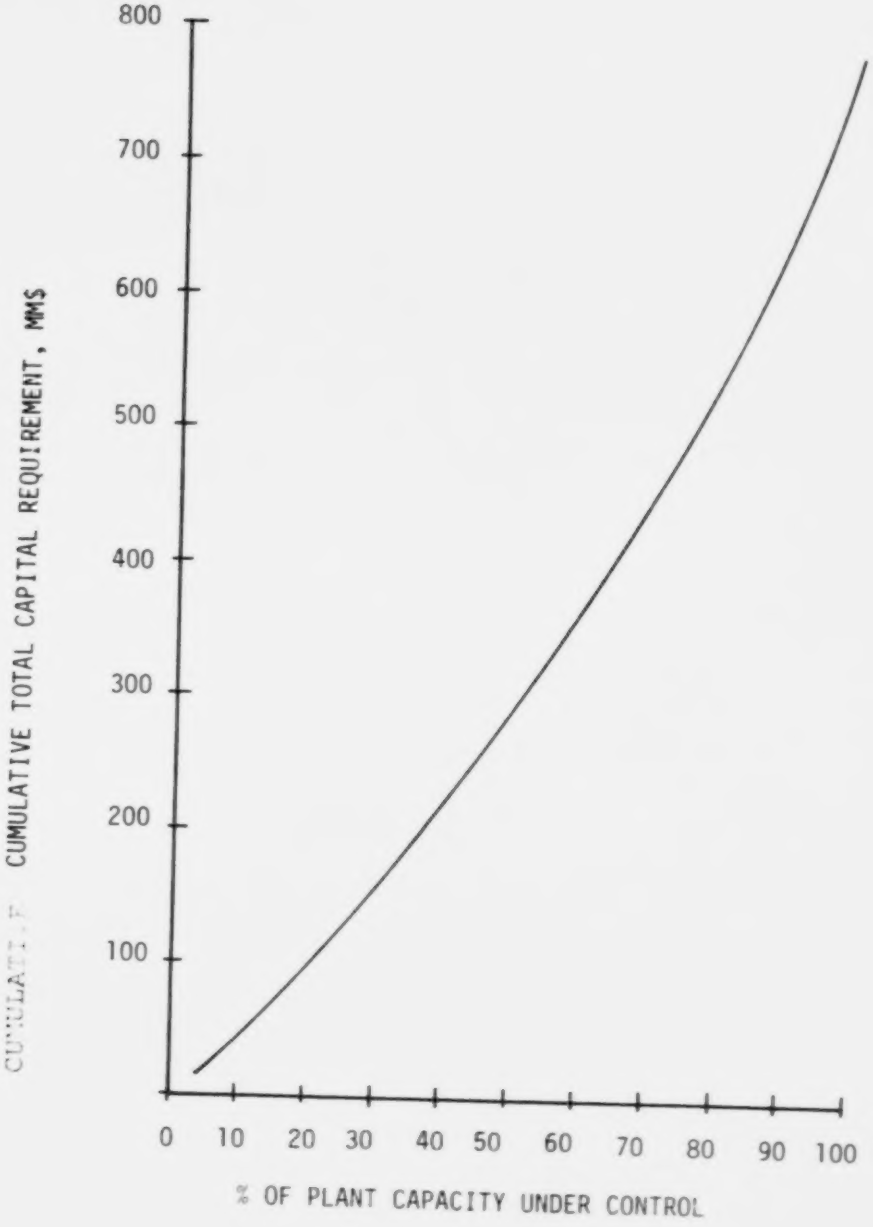


FIGURE 6.23

CUMULATIVE ANNUAL PRODUCTION COST OF WELLMAN-LORD STACK GAS SCRUBBING IN EXISTING SULFURIC ACID PLANTS

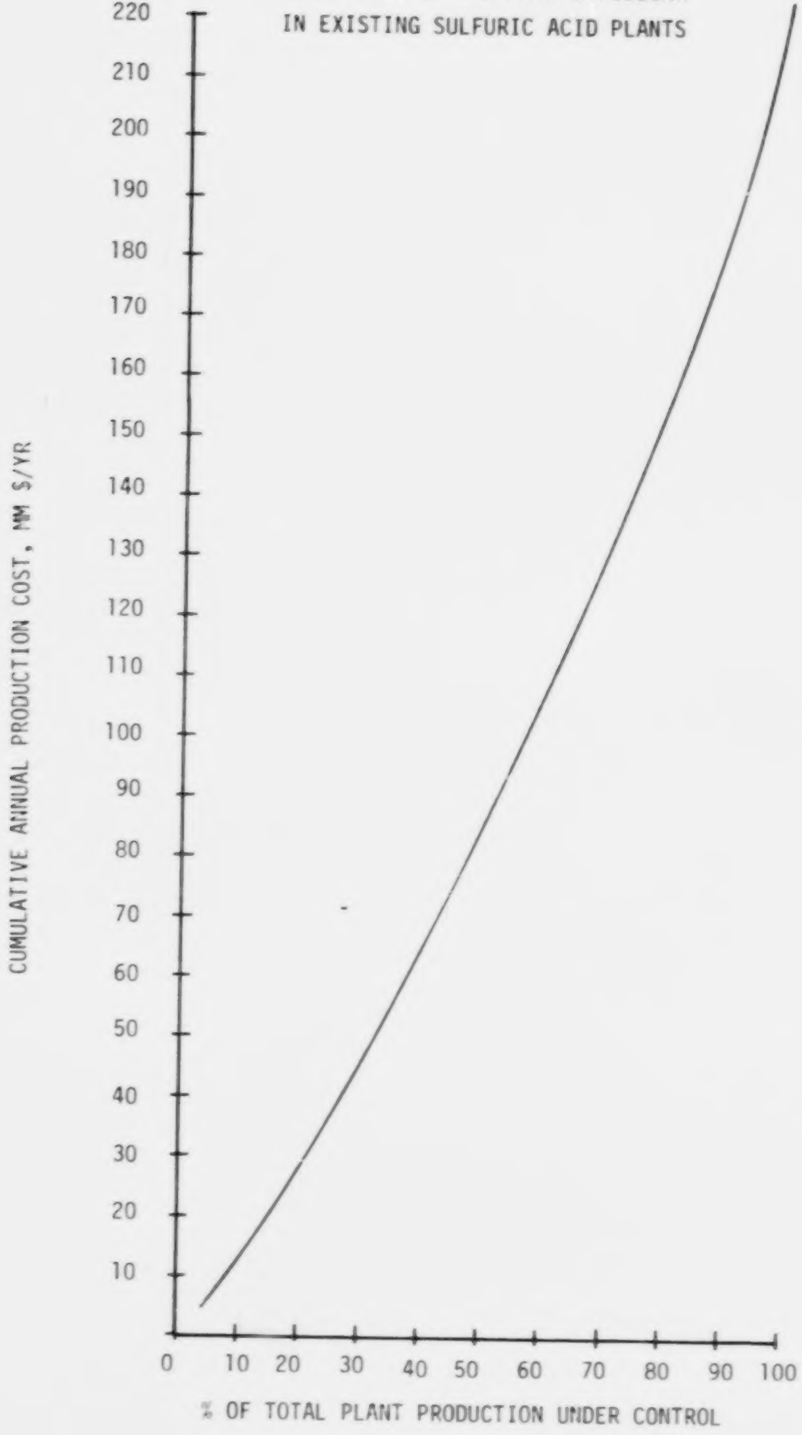
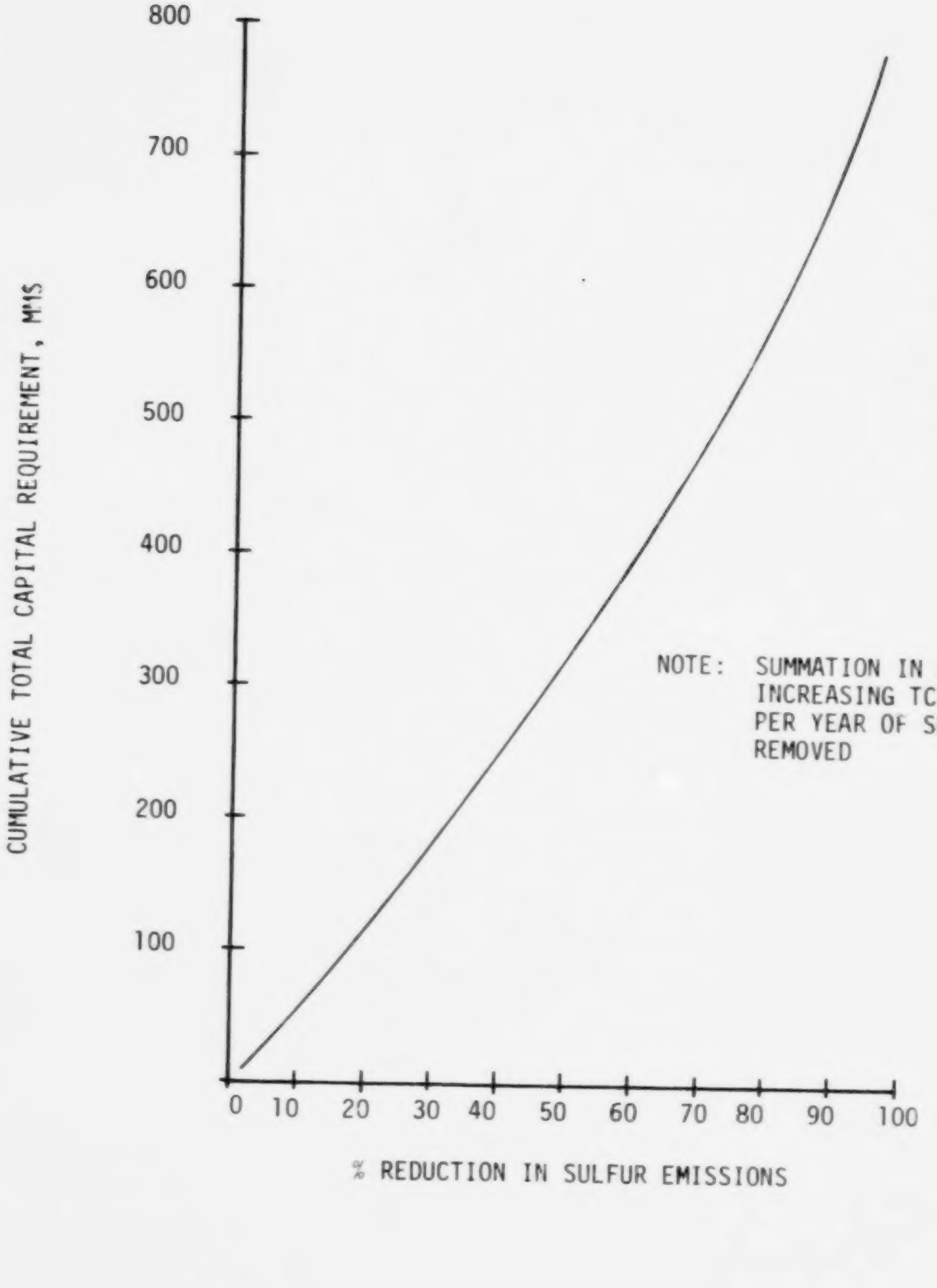


FIGURE 6.24

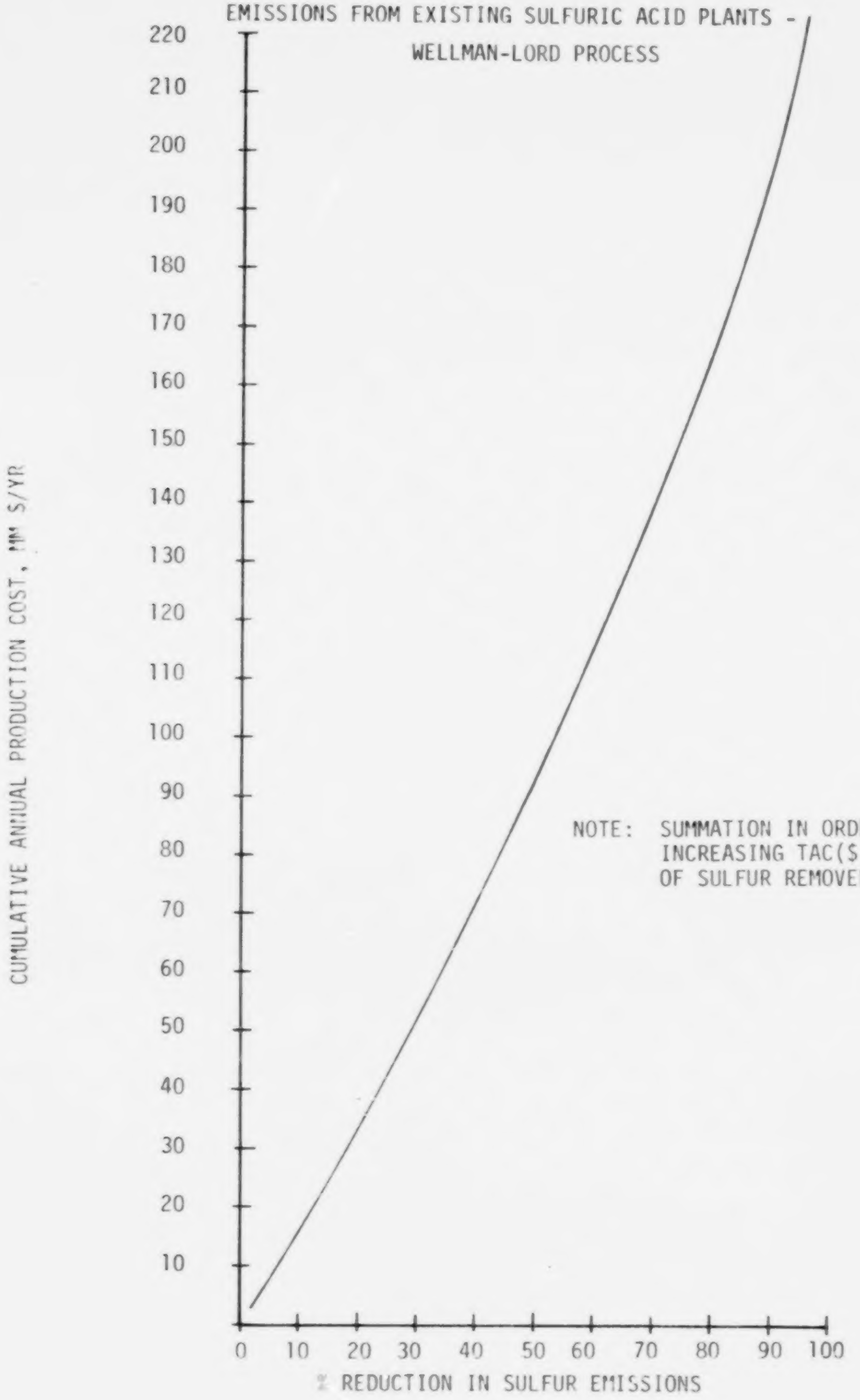
CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR REDUCING SULFUR EMISSIONS FROM EXISTING SULFURIC ACID PLANTS-WELLMAN-LORD PROCESS



NOTE: SUMMATION IN ORDER OF INCREASING TCR($)/TON PER YEAR OF SULFUR REMOVED

FIGURE 6.25

CUMULATIVE ANNUAL PRODUCTION COST OF REDUCING SULFUR EMISSIONS FROM EXISTING SULFURIC ACID PLANTS - WELLMAN-LORD PROCESS



NOTE: SUMMATION IN ORDER OF INCREASING TAC($)/TON OF SULFUR REMOVED

FIGURE 6.26
AVERAGE TOTAL CAPITAL REQUIREMENT
FOR INSTALLING STACK GAS SCRUBBING
IN EXISTING INDUSTRIAL BOILER PLANTS
(MM$)

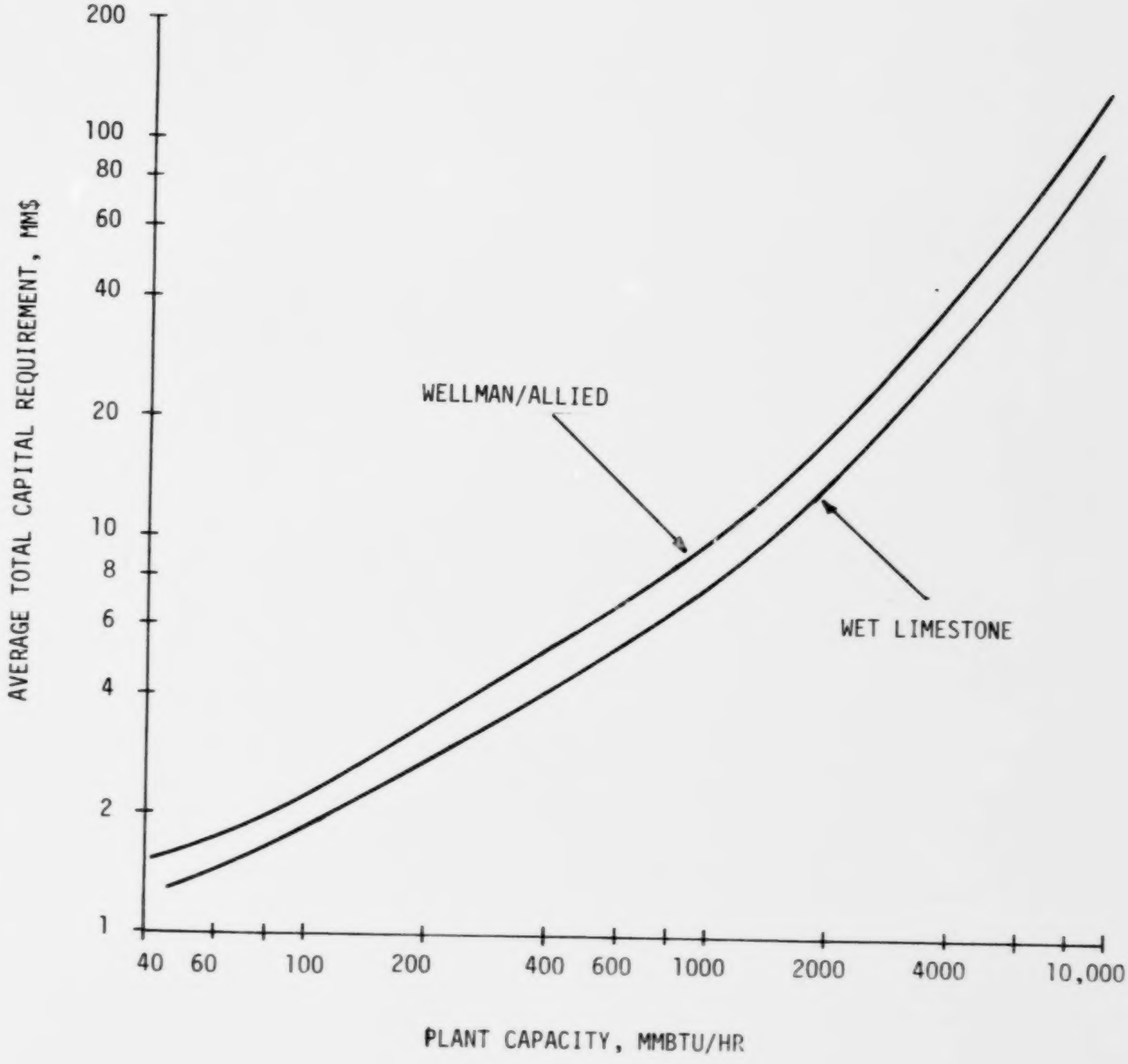


FIGURE 6.27
AVERAGE TOTAL CAPITAL REQUIREMENT
FOR INSTALLING STACK GAS SCRUBBING
IN EXISTING INDUSTRIAL BOILER PLANTS
($/MMBTU/YR)

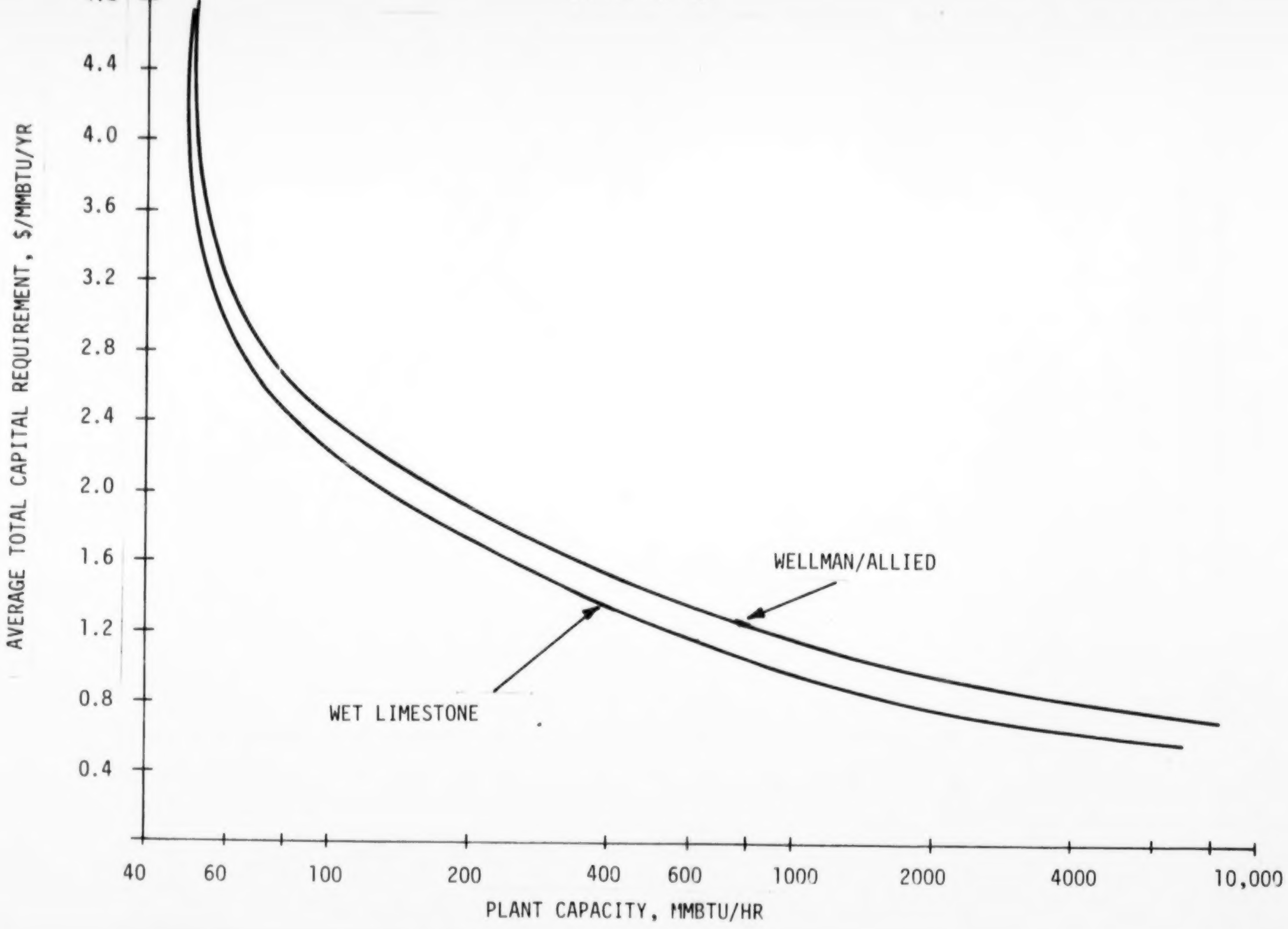


FIGURE 6.28

AVERAGE ANNUAL PRODUCTION COST OF STACK GAS SCRUBBING IN EXISTING INDUSTRIAL BOILER PLANTS

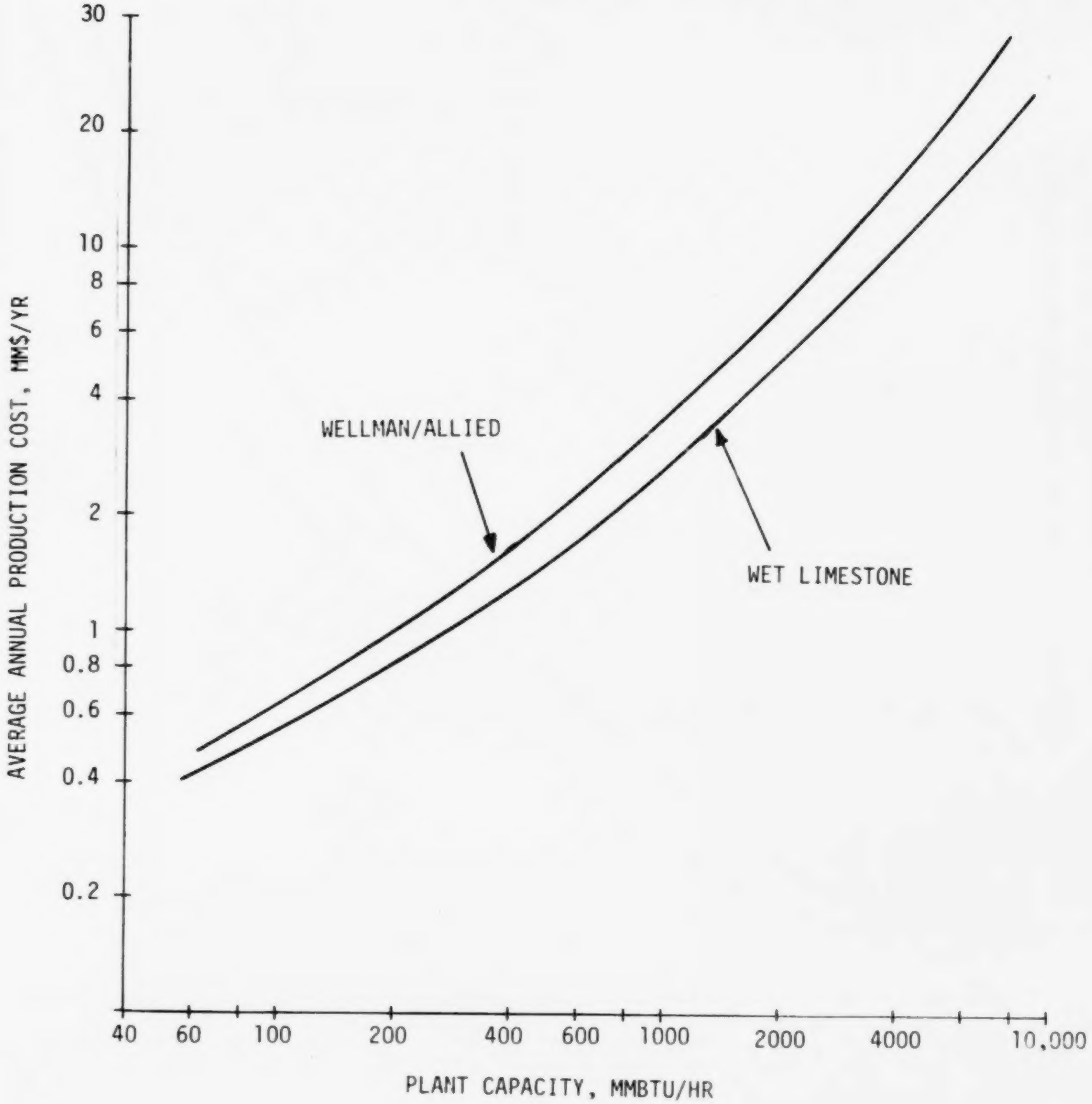


FIGURE 6.29
INCREMENTAL OPERATING COST OF STACK GAS
SCRUBBING IN EXISTING INDUSTRIAL BOILER PLANTS

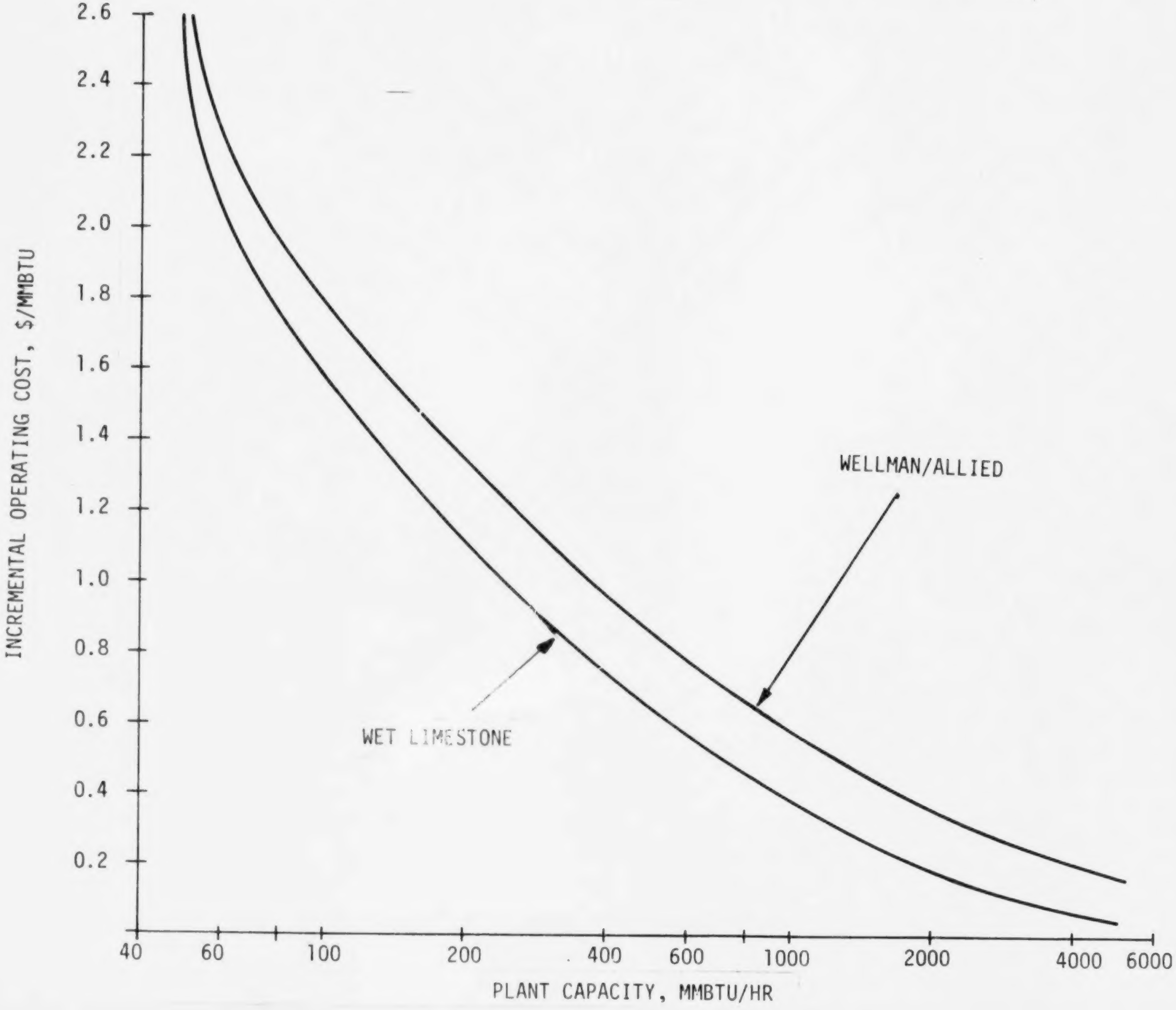


FIGURE 6.30

MAXIMUM TOTAL CAPITAL REQUIREMENT FOR INSTALLING STACK GAS SCRUBBING IN EXISTING INDUSTRIAL BOILER PLANTS ($/MMBTU/YR)

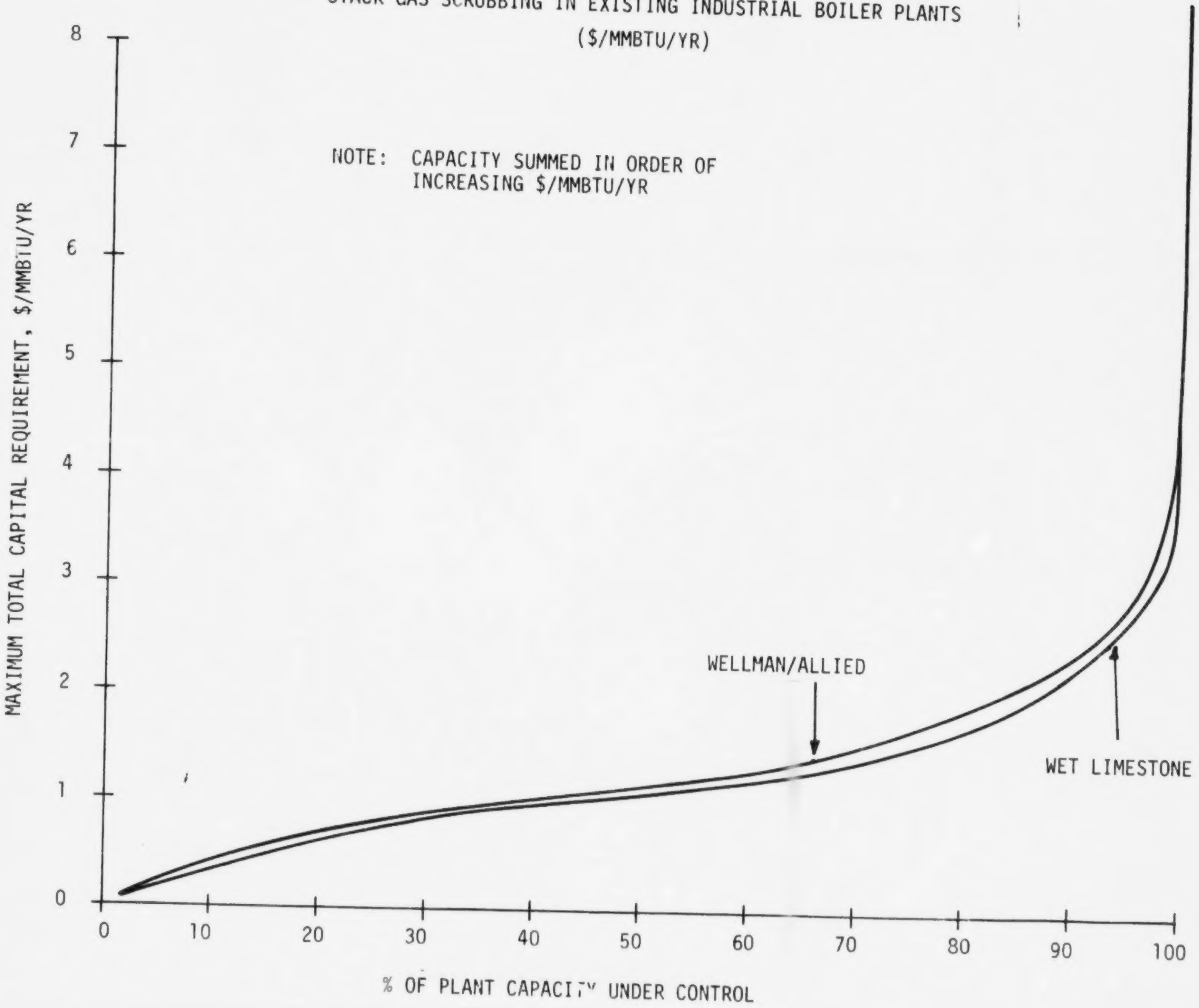
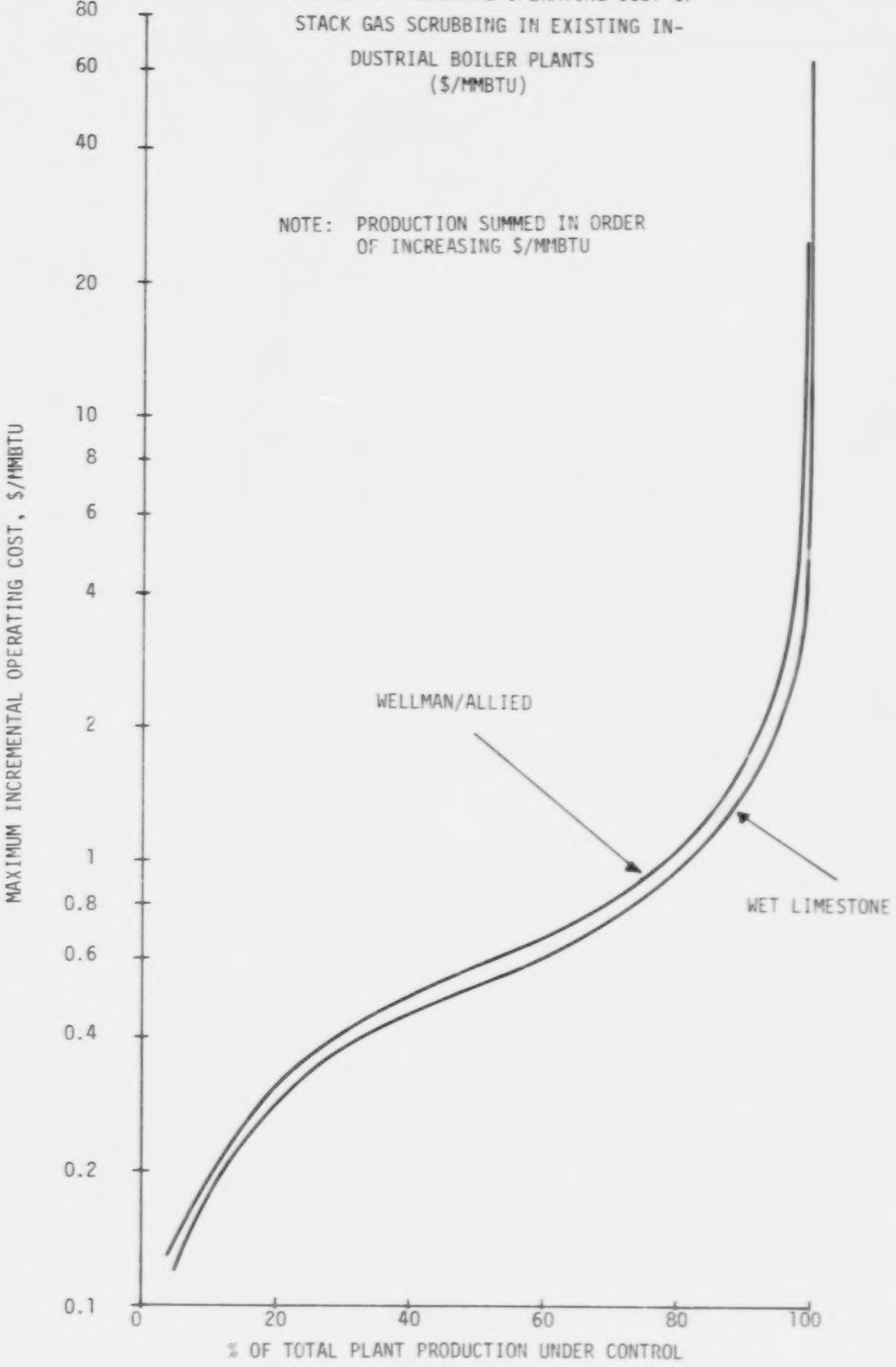

NOTE: CAPACITY SUMMED IN ORDER OF INCREASING $/MMBTU/YR

FIGURE 6.31

MAXIMUM INCREMENTAL OPERATING COST OF STACK GAS SCRUBBING IN EXISTING INDUSTRIAL BOILER PLANTS
($/MMBTU)



NOTE: PRODUCTION SUMMED IN ORDER OF INCREASING $/MMBTU

FIGURE 6.32

CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR INSTALLING STACK GAS SCRUBBING IN EXISTING INDUSTRIAL BOILER PLANTS (SUMMATION IN ORDER OF INCREASING $/MMBTU/YR)

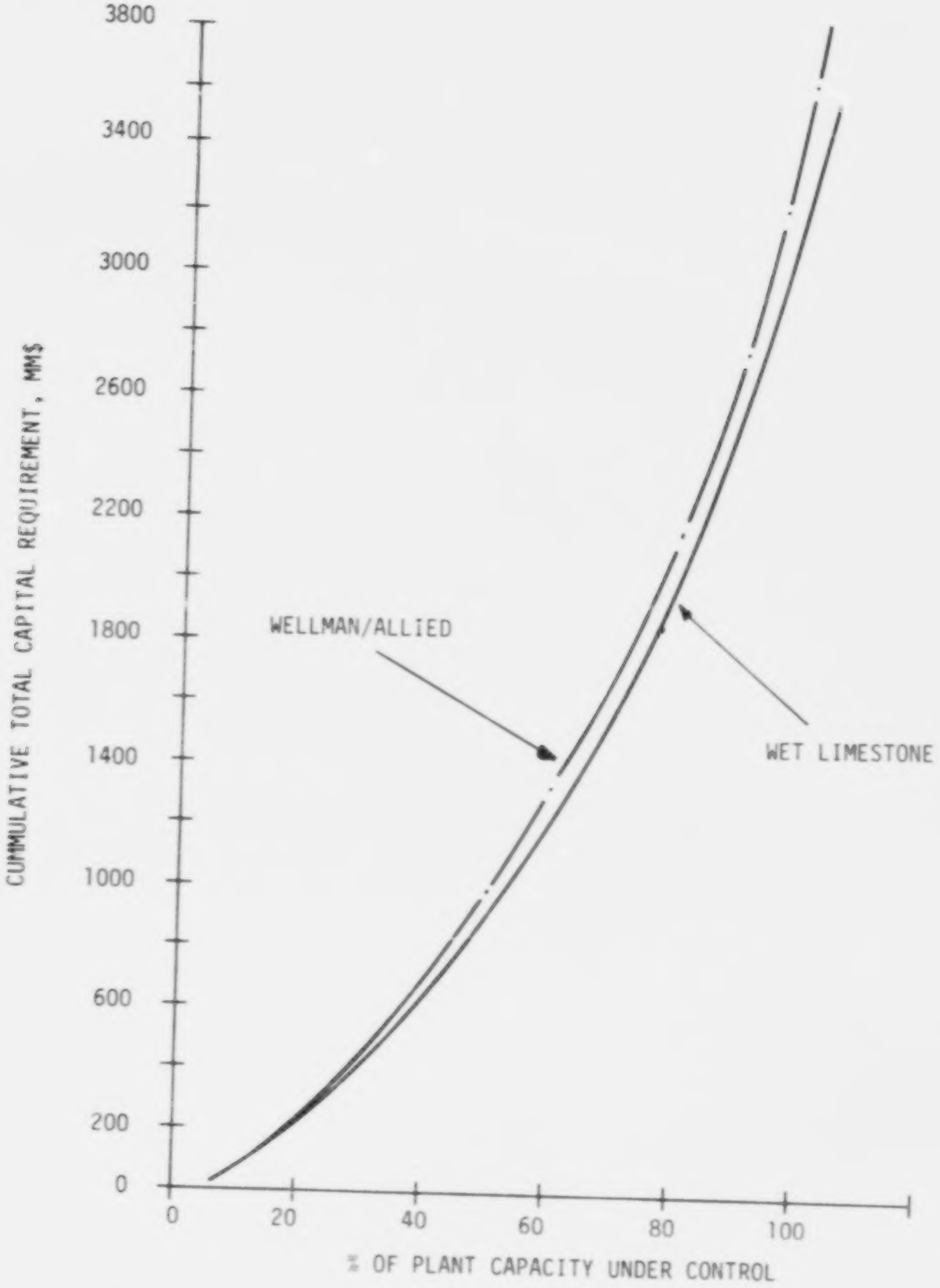


FIGURE 6.33
CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR
INSTALLING STACK GAS SCRUBBING IN
EXISTING INDUSTRIAL BOILER PLANTS
(SUMMATION IN ORDER OF DECREASING PLANT SIZE)

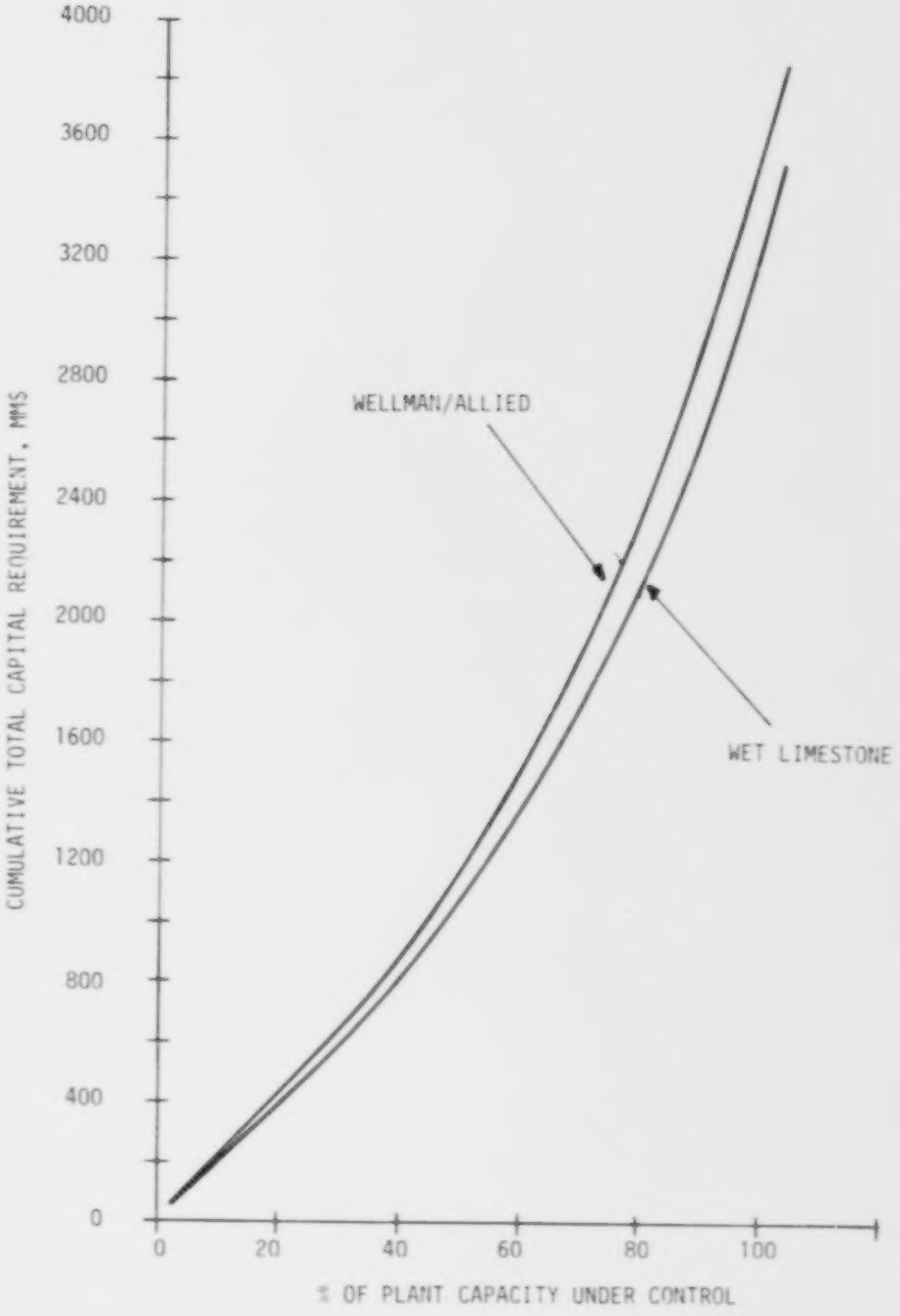


FIGURE 6.34

CUMULATIVE ANNUAL PRODUCTION COST OF STACK GAS STRUBBING IN EXISTING INDUSTRIAL BOILER PLANTS (SUMMATION IN ORDER OF INCREASING $/MMBTU)

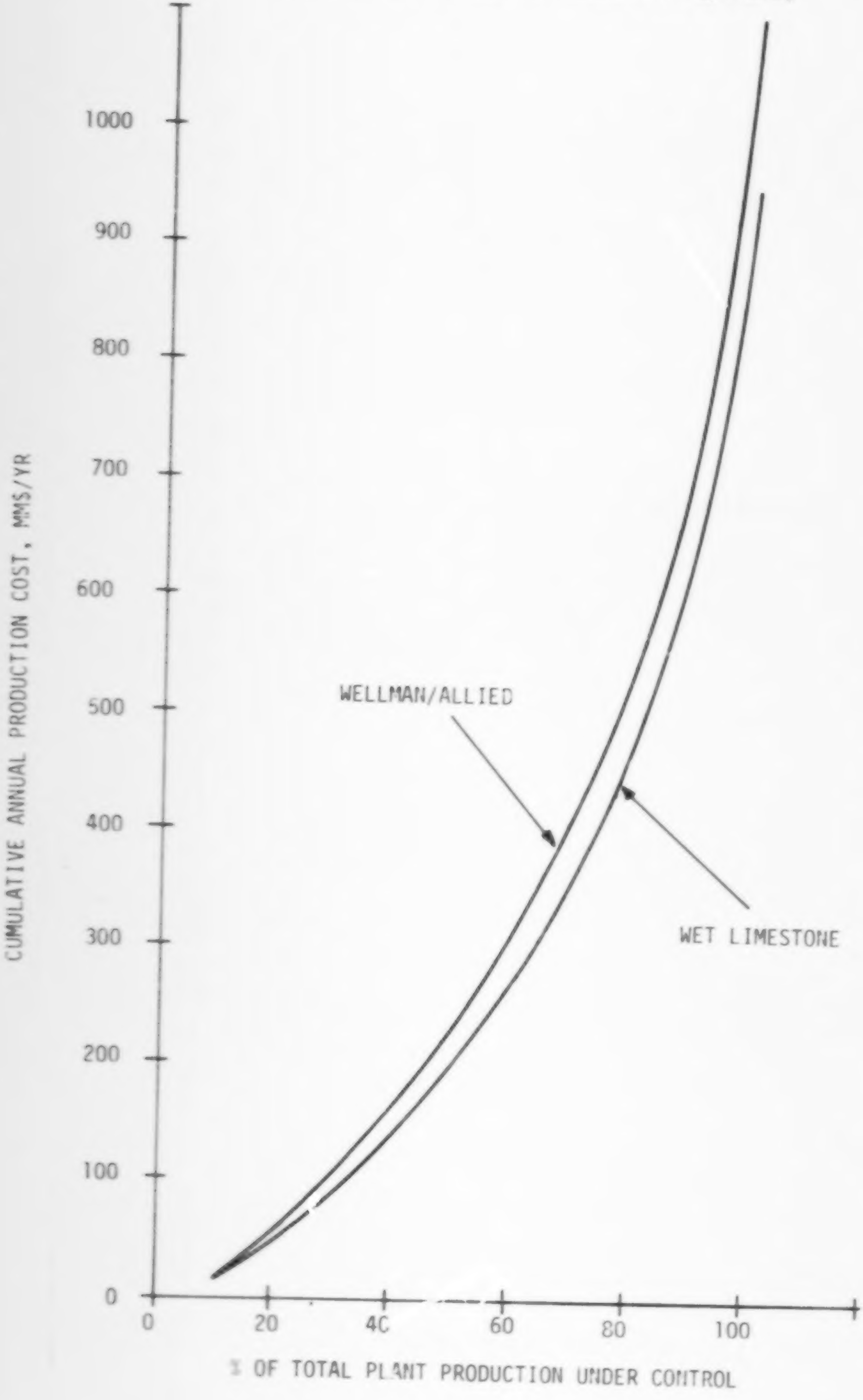


FIGURE 6.35

CUMULATIVE ANNUAL PRODUCTION COST OF STACK GAS SCRUBBING IN EXISTING INDUSTRIAL BOILER PLANTS (SUMMATION IN ORDER OF DECREASING PLANT PRODUCTION)

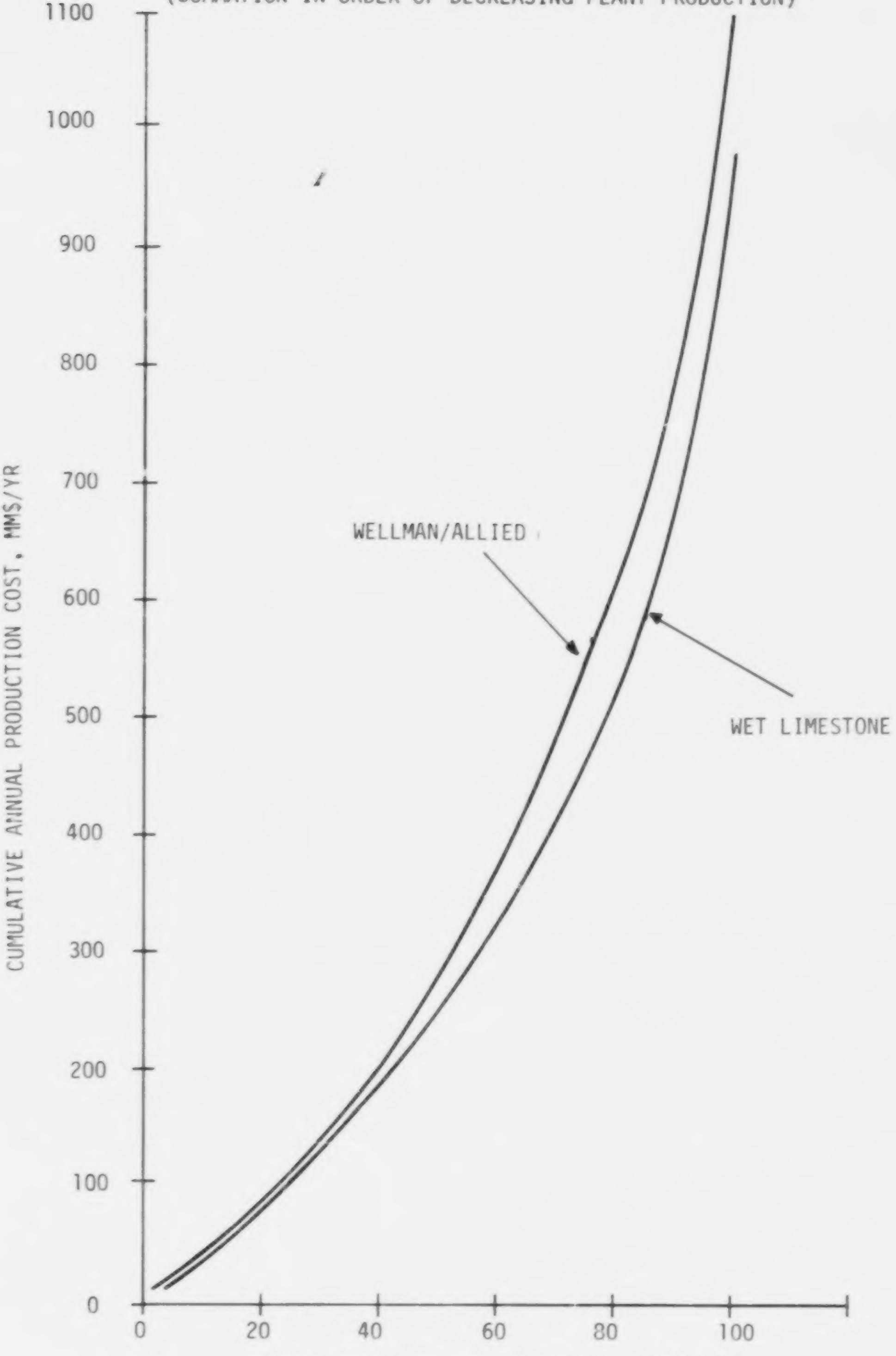


FIGURE 6.36

CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR REDUCING SULFUR EMISSIONS FROM EXISTING INDUSTRIAL BOILER PLANTS

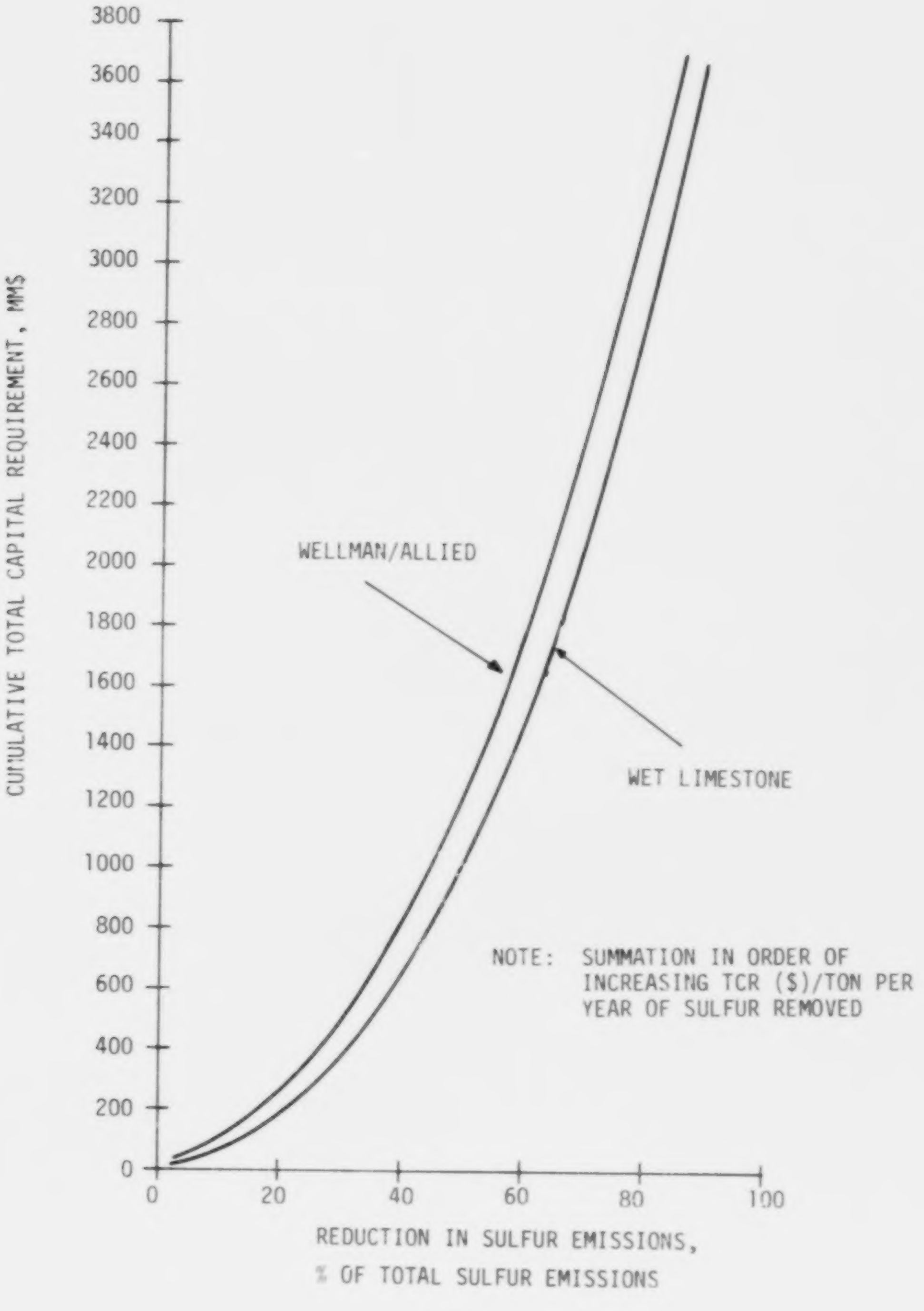


FIGURE 6.37
CUMULATIVE ANNUAL PRODUCTION COST OF REDUCING
SULFUR EMISSIONS FROM EXISTING INDUSTRIAL BOILER PLANTS

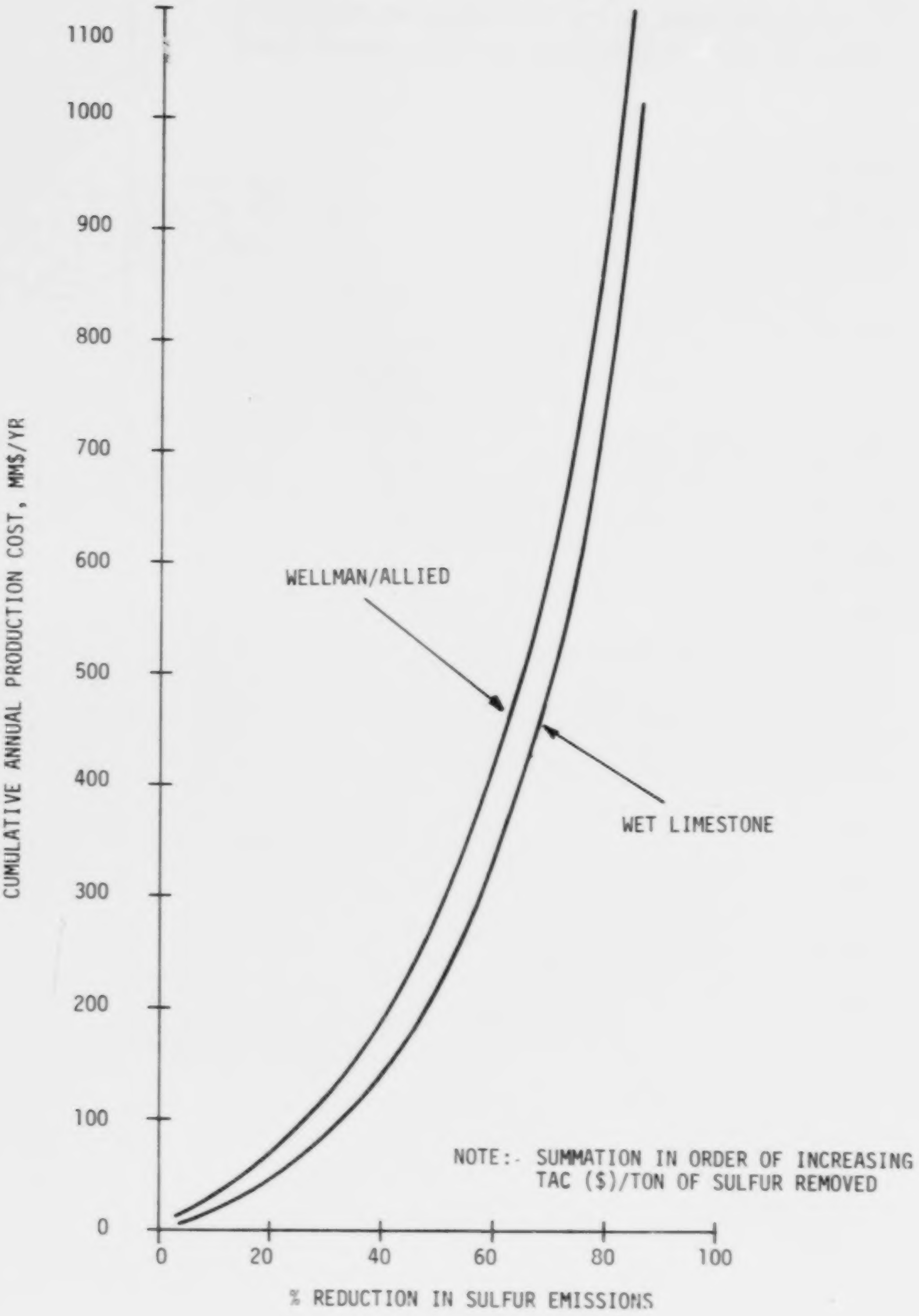
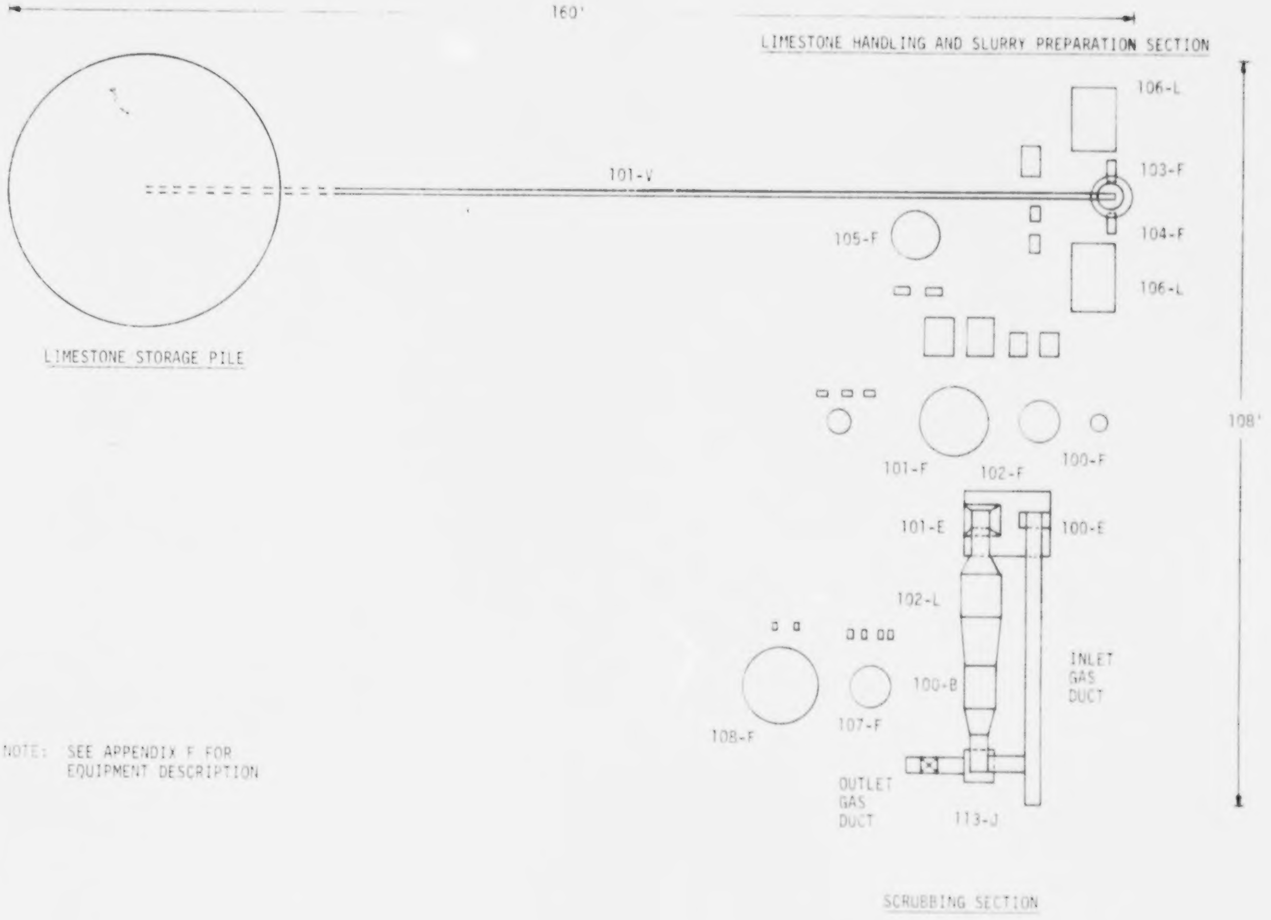


FIGURE 6.38

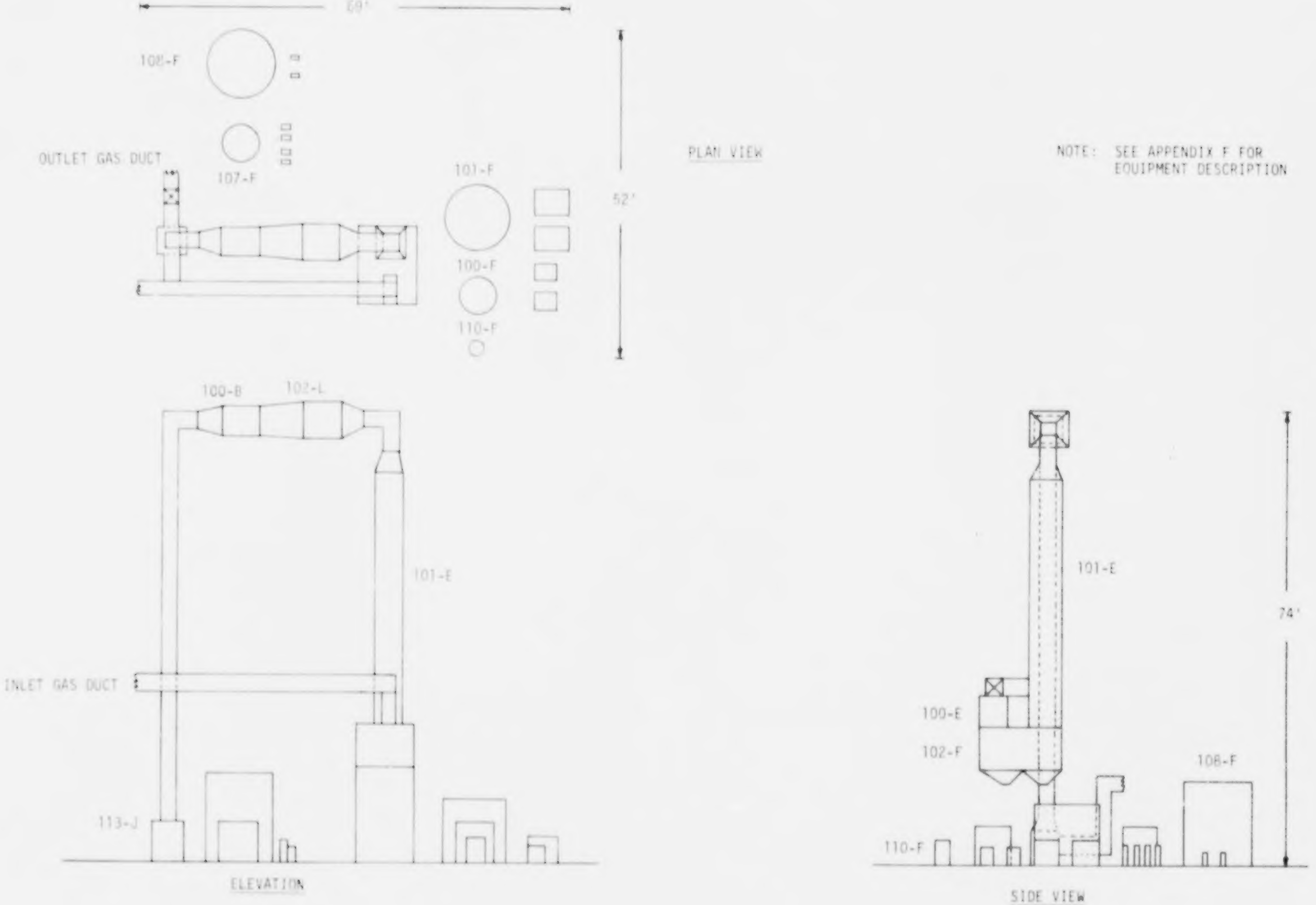
PACKAGED LIMESTONE SYSTEM FOR 50 MMBTU/HR INDUSTRIAL BOILER
OVERALL PLOT PLAN


160'
LIMESTONE HANDLING AND SLURRY PREPARATION SECTION
LIMESTONE STORAGE PILE
101-V
106-L
103-F
104-F
106-L
105-F
101-F
102-F
100-F
101-E
100-E
102-L
100-B
INLET GAS DUCT
108-F
107-F
OUTLET GAS DUCT
113-J
108'
SCRUBBING SECTION

NOTE: SEE APPENDIX F FOR
EQUIPMENT DESCRIPTION

FIGURE 6.39

PACKAGED LIMESTONE SYSTEM FOR 50 MMBTU/HR INDUSTRIAL BOILER
ARRANGEMENT OF SCRUBBING SECTION


69'
108-F
107-F
OUTLET GAS DUCT
101-F
100-F
110-F
52'
PLAN VIEW
100-B
102-L
101-E
INLET GAS DUCT
113-J
ELEVATION
101-E
74'
100-E
102-F
108-F
110-F
SIDE VIEW

NOTE: SEE APPENDIX F FOR
EQUIPMENT DESCRIPTION

7. COST OF FUEL CONVERSION

7.1 Costs of Mine Mouth Coal

Coal costs have been determined on the basis of sulfur content of coal. Average sulfur content of coal has been determined from coal analyses for various coals in a state (14). Coal cost based on this average sulfur content has been compared with the average purchase price of coal in a state (6). The two costs matched closely in all cases with the exception of the states of Illinois and West Virginia. Thus, it is generally justified to conclude that the coal mined was consumed within the state. If it is assumed that transportation charges within a state are relatively small compared to the coal cost, it is reasonable to infer that the average purchase price in a state approximates the mine-mouth cost of coal.

The average price paid for all purchases in the year 1973 for coal mined in Alabama was $12.80/ton. The average sulfur content of coal in Alabama was determined to be 1.5% (14). For coal with a sulfur content from 1.5 to 2%, the price paid was $12.91/ton. Therefore, a coal having a sulfur content of 1.5-2% was chosen as representative and an average price of $12.80/ton was used as the mine-mouth price. There was similar agreement in prices in the case of all states other than the ones described below.

In Illinois, 70% of the coal purchased contained over 2% sulfur and about 24% of the coal had less than 0.5% sulfur. As there are no known deposits of low sulfur coal in Illinois, it is evident that the coal was imported from out of state sources. In this case, the coal cost has been taken as the average cost for coal containing more than 2% sulfur. There is substantial deviation between the average price of coal and the price based on sulfur content in the case of West Virginia. The purchase price of coal in the 2-3% sulfur range has been used for calculation of SNG and SPC costs in that state.

Based on the average sulfur content, coal costs for different coal producing states have been obtained from published sources (6) and are presented in Table No. 7.1.

7.2 Costs of Mine-Mouth SNG

The cost of production of SNG varies from \$1.14/MMBtu in Texas to \$2.67/MMBtu in Virginia, corresponding to coal costs of \$1.90/ton and \$25.61/ton respectively. The cost of production of SNG is the highest in several eastern states (Ohio, Pennsylvania, Virginia and West Virginia), ranging from \$2.00/MMBtu to \$2.70/MMBtu. This is due to higher coal and labor costs. The cost of SNG production in several western states (Colorado, Montana, New Mexico and Wyoming) is low due to the availability of inexpensive coal, and ranges from \$1.25/MMBtu to \$1.60/MMBtu. Costs in some mid-western (Illinois, Indiana and Missouri) and southern (Alabama, Kentucky and Tennessee) states would represent costs closer to the average cost and vary from \$1.65/MMBtu to \$1.95/MMBtu.

The cost of producing SNG was found to be the lowest in Texas due to availability of the least expensive coal and to lower labor costs. Virginia coal is the most expensive and results in the highest SNG cost.

The procedure to evaluate total annual cost of production is shown in the General Cost Model in appendix C. A sample calculation of the cost of SNG is given in appendix G.

7.3 Cost Model for Production of Intermediate Btu Gas

The model represents a plant producing 125 x 10^9 Btu/day of intermediate Btu gas having a higher heating value of 323 Btu/SCF (dry).

7.3.1 Electric Power and High Pressure Steam Requirements for the Intermediate Btu Gas Plant

1. In this model all drivers are powered by electricity. The total power requirement for the plant is about 63 MW.

2. Steam generated during waste heat recovery produces about 18 MW power.

3. Intermediate Btu gas, after sulfur removal, is expanded in two stages to produce about 45 MW power. Gas is re-heated by hot crude gas in between the expansion stages.

4. Steam required for process units is produced partly during the cooling of crude gas from the gasifier, and partly in the Claus plant.

5. About 10% of the 550 psig steam required for gasification is generated in the gasifier jacket and the remainder is obtained by burning tar and tar oils in a boiler.

7.3.2 Major Equipment Costs, E

The intermediate Btu gas plant has been divided into the following 10 sections

Section Number	Solid Handling (S) Chemical Processing (C)	Unit
1	S	Coal Preparation and Handling
2	S	Fines Agglomeration
3	S	Coal Gasification
4	C	Gas Cooling
5	C	Gas Purification by Benfield Process
6	C	Oxygen Plant
7	C	The Phenosolvan Unit
8	C	Sulfur Recovery - Claus Plant
9	C	The Utility Plant
10	C	Other Offsites

Equipment costs have been developed using published data and in-house information (5,9). Costs are for end of 1973 and for a U.S. Gulf Coast location. Section No. 1, 2, 3, 6, 7 and 9 are similar to SNG plant and are described in detail in Part 1 of this study.

Section 1 - Coal Preparation and Handling

Raw coal from storage is crushed and classified in this section. No variations in E have been determined with the coal type.

$$E1 = 1250 \qquad \text{M \$}$$

Section 2 - Fines Agglomeration

Coal flow to the fines agglomeration unit decreases as the carbon content of coal increases.

$$E2 = 2560-50\,(PCARB-65) \qquad \text{M \$}$$

Section 3 - Coal Gasification

The number of gasifiers required depends on the quantity of the coal feed, the slagging properties of the coal and the reactivity of the coal.

E3 = 6410 + 70 (PCARB-65) M $

Section 4 - Gas Cooling

The crude gas from the gasifier is cooled before sending it to the gas purification unit. No significant variations in cost could be determined with the carbon content.

E4 = 800 M $

Section 5 - Gas Purification by the Benfield Process

This unit selectively removes H_2S from the gas. H_2S is removed to the extent of meeting emission standards. Gas purification is not required for low sulfur coals. The increase in cost with increase in sulfur content of coal is not significant.

E5 = 1400 M $

Section 6 - Oxygen Plant

The oxygen requirements for the gasifier increase with increasing carbon content of the coal.

E6 = 4960 + 80 (PCARB-65) M $

Section 7 - The Phenosolvan Unit

This unit handles all the gas liquor which has been condensed. Here, the main objective is to recover phenol and tars.

$$E7 = 920 \qquad \text{M\$}$$

Section 8 - Sulfur Recovery in Claus Plant

Here H_2S removed during gas purification is converted to elemental sulfur. It has been assumed that 80% of the sulfur in coal is recovered as elemental sulfur. There is an increase in cost as the sulfur content of coal increases. The sulfur recovery plant is not required for low sulfur coals.

$$E8 = 280\ (\mathrm{TDAFC} \cdot \mathrm{PSULF})^{0.6} + 90\ \mathrm{PSULF} - 200 \quad \text{M\$}$$

where PSULF is the percentage sulfur in coal on a dry ash free basis.

Section 9 - The Utility Plant

The utility plant supplies power and generates steam for the gasifiers. The boiler plant increases in size as the carbon content of coal increases. The rest of the unit has been assumed to be independent of the coal type and has a major equipment cost of 4600 M\$.

$$E9 = 7500 + 60\ (\mathrm{PCARB}-65) \qquad \text{M\$}$$

Section 10 - Other Offsites

This includes storage facilities, service systems, electrical distribution, sewers and waste disposal, site preparation, plant buildings and mobile equipment.

$$\mathrm{E10} = 6500 \qquad \mathrm{M\ \$}$$

7.3.3 Total Capital Requirement and Net Annual Operating Cost

The Total Plant Investment has been derived from the cost of major equipment. The Total Capital Requirement and the Net Annual Production Cost are calculated using the procedures of the General Cost Model, which is fully explained in Appendix C.

7.3.4 Annual Raw Material Requirements

The total dry ash free coal requirement (TDAFC) of a 125×10^9 Btu/day intermediate Btu gas plant is given by:

$$\mathrm{TDAFC} = 0.651 - 0.0067\ (\mathrm{PCARB}-65) \quad \text{million lb/hr}$$

The total "as received coal" requirement of a 125×10^9 Btu/day intermediate Btu gas plant is given by:

$$\mathrm{TCOAL} = 100\ \mathrm{TDAFC}/(100-\mathrm{PH20}-\mathrm{PASH}) \quad \text{million lb/hr}$$

where PH20 and PASH are the moisture and ash contents of coal respectively.

The annual cost of raw materials less by product credits is given by:

$$\mathrm{ANR} = \mathrm{ACOAL} + \mathrm{ACHEM} - \mathrm{ASULF}$$

The annual cost of catalysts and chemicals, ACHEM, is assumed constant at 400 M$.

The annual cost of the coal feed to the plant, ACOAL, is given by:

$$\mathrm{ACOAL} = 12\ \mathrm{CCOAL} \cdot \mathrm{TCOAL} \cdot \mathrm{SD} \qquad \mathrm{M\$/yr.}$$

where CCOAL is the unit cost of coal as received at the site in $/ton and SD is the number of days the plant is on stream per year.

The credit per year for the sale of sulfur, ASULF, is given by:

$$\mathrm{ASULF} = 0.1\ \mathrm{CSULF} \cdot \mathrm{TDAFC} \cdot \mathrm{PSULF} \cdot \mathrm{SD} \qquad \mathrm{M\$/yr.}$$

where CSULF is the unit credit for sulfur in $/ton. It has been assumed that 80% of the sulfur in the coal feed to the plant is recovered.

The total number of shift operators for the intermediate Btu gas plant can be assumed to be 150.

An example is provided in appendix H to illustrate cost calculations from the model.

Figures 7.4 and 7.5 illustrate the effects of change in carbon and sulfur content of coal on the capital and production costs. Figure 7.6 shows the effect of location factor on the costs of production.

7.4 Cost Model for Production of Low Btu Gas

This model represents a plant producing 125×10^9 Btu/day of low Btu gas having a higher heating value of 196 Btu/SCF (dry).

7.4.1 Electric Power and High Pressure Steam Requirement for the Low Btu Gas Plant

1. In this model all drivers are powered by electricity. The total power requirement for the plant is about 16 MW.

2. Low Btu gas after sulfur removal is expanded in two stages to produce about 62 MW power. Purified low Btu gas is re-heated by hot crude gas between expansion stages.

3. Steam required for the coal gasifiers is produced by burning tar and tar oils in a boiler. About 25% of the gasifier steam is generated in the gasifier jacket.

4. Steam required for process units is obtained from the tar fired boiler and from the Claus plant.

5. About 46 MW net power is available from the plant.

7.4.2 Major Equipment Costs, E

The low Btu gas plant has been divided into the following 10 units:

Section Number	Solid Handling (S) Chemical Handling (C)	Unit
1	S	Coal Preparation and Handling
2	S	Fines Agglomeration
3	S	Coal Gasification

Section Number	Solid Handling (S) Chemical Handling (C)	Unit
4	C	Gas Cooling
5	C	Gas Purification by Benfield Process
6	C	Air Compression
7	C	The Phenosolvan Unit
8	C	Sulfur Recovery Claus Plant
9	C	The Utility Plant
10	C	Other Offsites

The major equipment costs for a 125×10^9 Btu/day low Btu gas plant are:

Section 1 - Coal Preparation and Handling

Raw coal from storage is crushed and classified in this section. No variations in E have been determined with the coal type.

E1 = 1300 M $

Section 2 - Fines Agglomeration

The coal flow to the fines agglomeration unit decreases as the carbon content of coal increases.

E2 = 2640 - 50 (PCARB-65) M $

Section 3 - Coal Gasification

The number of gasifiers required depends on the quantity of the coal feed, the slagging properties of the coal and the reactivity of the coal.

E3 = 6900 + 80 (PCARB-65) M $

Section 4 - Gas Cooling

The crude gas from gasifier is cooled before gas purification in the Benfield system. There is no change in cost with variation in the carbon content of the coal.

$$E4 = 700 \qquad \text{M \$}$$

Section 5 - Gas Purification by the Benfield Process

This unit removes H_2S selectively from the gas to the extent of meeting the allowable emission standards. Gas purification is not required for the gas produced from low sulfur coal. The increase in cost is not significant as the sulfur content of the coal increases.

$$E5 = 1780 \qquad \text{M \$}$$

Section 6 - The Phenosolvan Unit

This unit handles all the gas liquor which has condensed. Here, the main objective is to recover phenol and tars. No significant cost variations could be determined in general terms.

$$E6 = 950 \qquad \text{M \$}$$

Section 7 - Sulfur Recovery by Claus Plant

H_2S removed during the purification of gas by the Benfield process is converted to elemental sulfur. It has been assumed that 80% of the sulfur in coal is recovered as elemental sulfur. There is an increase in the equipment cost as the sulfur content of coal increases. However, for low sulfur coals the sulfur recovery plant is not required.

$$E7 = 290\ (TDAFC \cdot PSULF)^{0.6} + 100\ PSULF - 210 \quad M\ \$$$

where PSULF is percentage of sulfur in dry ash free coal.

Section 8 - The Utility Plant

The utility plant supplies power and steam to the plant. Power is generated by expansion of the purified gas in two stages. Steam is raised in a tar-fired boiler. The boiler plant increases in size as the carbon content of coal increases. The rest of the unit is assumed to be independent of the coal type and has a major equipment cost of 3600 M$.

$$E8 = 5640 + 50\ (PCARB-65) \qquad M\ \$$$

Section 9 - Air Compressors

In this section air required for gasification is compressed to 320 psig. There is a slight increase in cost as the carbon content of coal increases.

$$E9 = 850 + 20\ (PCARB-65) \qquad M\ \$$$

Section 10 - Other Offsites

This includes storage facilities, service systems, electrical distribution, sewers and waste disposal, site preparation, plant buildings, and mobile equipment.

$$E10 = 6000 \qquad M\ \$$$

7.4.3 Total Capital Requirement and Net Operating Cost

This model conforms exactly to the format in the General Cost Model, which is fully explained in Appendix C. The Total Plant Investment has been derived from the cost of major equipment. The Total Capital Requirement and The Net Annual Production Cost are calculated using the procedures of the General Cost Model.

7.4.4 Annual Raw Material Requirements

The total dry ash free coal requirement (TDAFC) of a 125 x 10^9 Btu/day low Btu gas plant is:

$$TDAFC = 0.683 - 0.0071\ (PCARB-65)\quad \text{million lb/hr.}$$

The total "as received coal" requirement of a 125 x 10^9 Btu/day low Btu gas plant is given by:

$$TCOAL = 100\ TDAFC/(100-PH2O-PASH)\quad \text{million lb/hr.}$$

where PH2O and PASH are the moisture and ash contents of coal respectively.

The annual cost of raw materials less by product credits is given by:

$$ANR = ACOAL + ACHEM - ASULF - APOWER.$$

The annual cost of raw materials and chemicals, ACHEM, is assumed constant at 420 M$.

The annual cost of the coal feed to the plant, ACOAL, is given by:

$$ACOAL = 12\ CCOAL \cdot TCOAL \cdot SD \qquad M\$/yr.$$

where CCOAL is the unit cost of coal as received at the site in $/ton and SD is the number of days the plant is on stream per year.

The credit per year for the sale of sulfur, ASULF, is given by:

$$ASULF = 0.1\ CSULF \cdot TDAFC \cdot PSULF \cdot SD \qquad M\$/yr$$

where CSULF is the unit credit for sulfur in $/ton. It has been assumed that 80% of the sulfur in the coal feed to the plant is recovered.

APOWER is the annual credit for power available for sale and is given by:

$$APOWER = 1.1 \times CPOWER \times SD \qquad M\ \$$$

where CPOWER is the cost of power in mills/KWH.

The total number of shift operators for the low Btu gas plant can be assumed to be 150.

An example is provided in appendix I to illustrate cost calculations from the model.

Figures 7.8 and 7.9 illustrate the effects of change in carbon and sulfur content of coal on the capital and production costs. Figure 7.10 shows the effect of location factor on the cost of production.

7.5 Cost of Mine-Mouth SRC

Costs have been calculated based on the following assumptions:

1. 80% of the coal is converted to SRC on a Btu basis.
2. The amount of cresylic acid produced from a 250 x 10^9 Btu/day SRC plant is constant at 170 Tons/day.
3. 40% of the sulfur present in the coal is recovered as by-product sulfur.

SRC costs have not been determined for the states of Colorado, Montana, New Mexico, Virginia and Wyoming. Most of the coal mined in these states contains less than 1% sulfur and it is more practical to burn these low sulfur coals in existing coal fired boilers. On the basis of cost per MMBtu, SRC costs are 55-60% of SNG costs. SRC costs for various locations are plotted on the map (Fig. 7.11) and tabulated in Table 7.1.

The procedure to evaluate total annual cost of production of SRC is shown in the General Cost Model in appendix C. A sample calculation of the cost of SRC is given in appendix G.

Table 7.1

Mine-Mouth Cost of Coal, SNG, and SRC

State	Coal, $/ton	SNG, $/MM BTU	SRC, $/MM BTU
Alabama	12.80	1.87	1.11
Colorado	7.21	1.58	-
Illinois	8.64	1.85	1.06
Indiana	8.49	1.97	1.15
Kentucky	11.49	1.88	1.10
Missouri	7.66	1.81	1.00
Montana	3.73	1.43	-
New Mexico	3.36	1.29	-
North Dakota	2.26	1.29	0.73
Ohio	14.43	2.22	1.31
Pennsylvania	15.05	2.21	1.31
Tennessee	9.18	1.69	0.96
Texas	1.90	1.15	0.64
Virginia	25.61	2.69	-
West Virginia	11.48	2.03	1.18
Wyoming	3.30	1.27	-

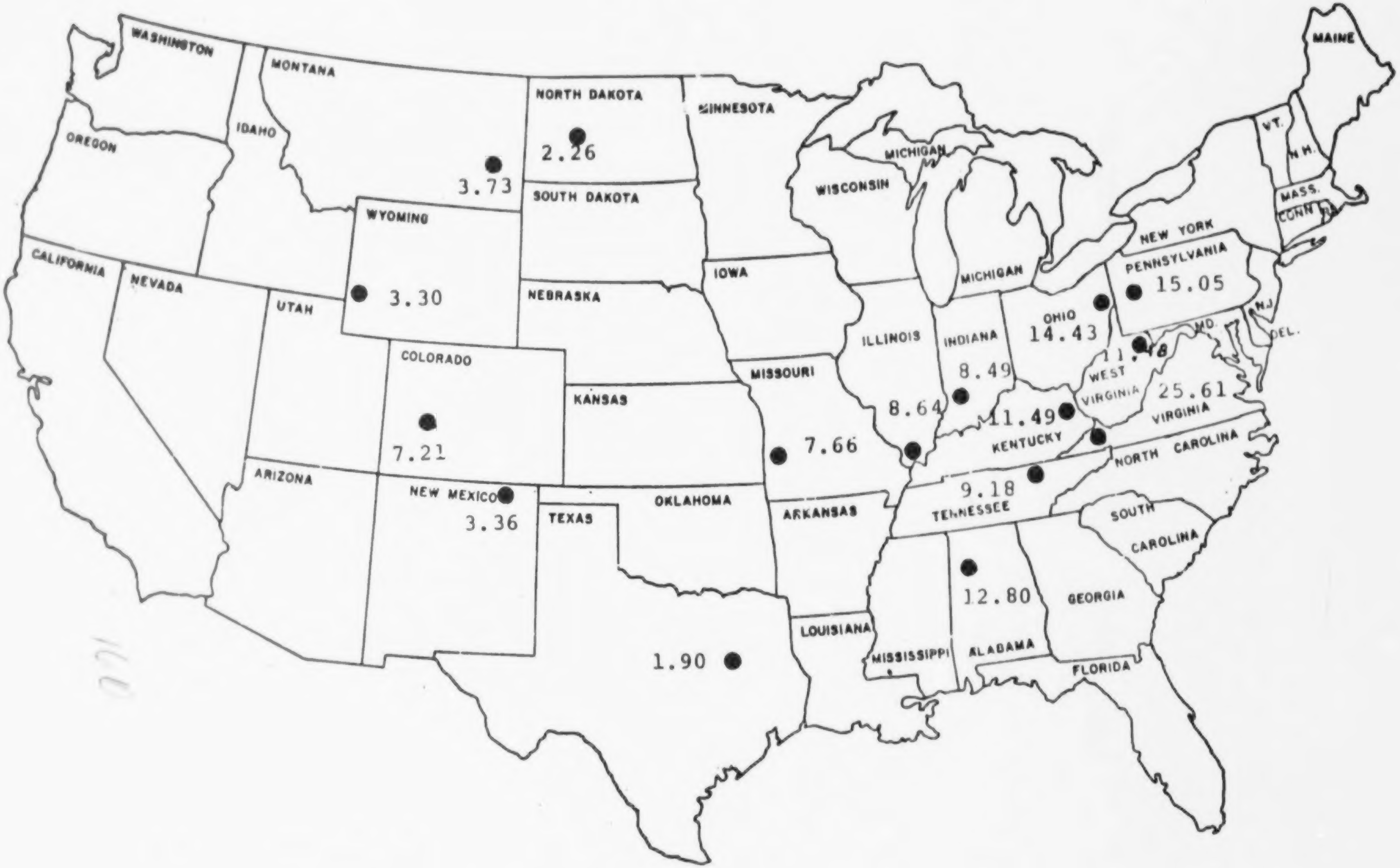

WASHINGTON
MONTANA
NORTH DAKOTA
MINNESOTA
MAINE
OREGON
IDAHO
2.26
3.73
MICHIGAN
WISCONSIN
VT.
N.H.
MASS.
CONN
R.I.
SOUTH DAKOTA
WYOMING
NEW YORK
PENNSYLVANIA
15.05
CALIFORNIA
NEVADA
UTAH
3.30
NEBRASKA
IOWA
MICHIGAN
ILLINOIS
INDIANA
OHIO
14.43
N.J.
MD.
DEL.
COLORADO
MISSOURI
8.49
11.48
WEST VIRGINIA
25.61
VIRGINIA
KANSAS
8.64
11.49
KENTUCKY
7.21
7.66
NORTH CAROLINA
ARIZONA
NEW MEXICO
3.36
TEXAS
OKLAHOMA
ARKANSAS
9.18
TENNESSEE
SOUTH CAROLINA
12.80
GEORGIA
LOUISIANA
MISSISSIPPI
ALABAMA
1.90
FLORIDA

FIGURE 7.1
MINE-MOUTH COST OF COAL
($/ton)

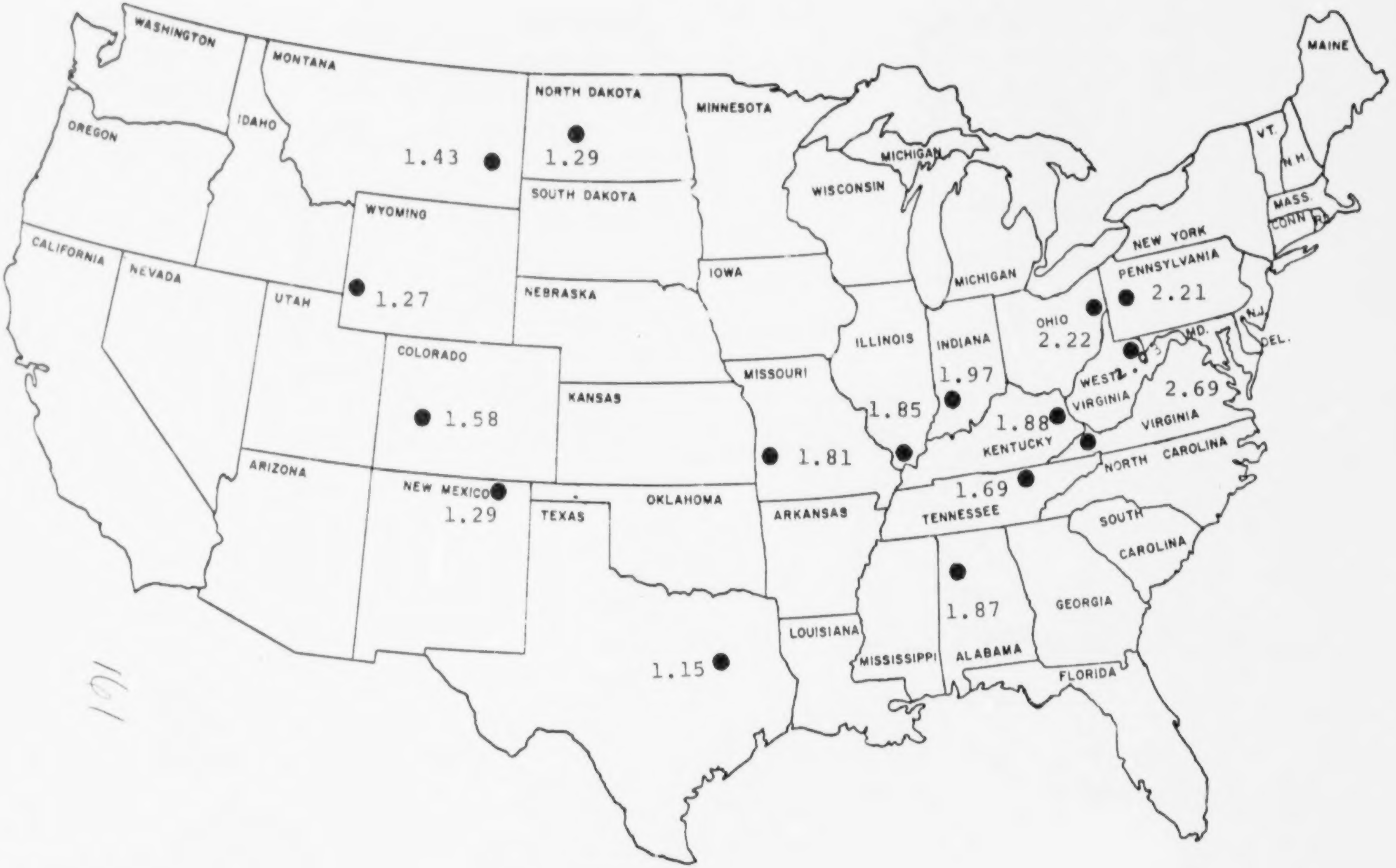

WASHINGTON
OREGON
CALIFORNIA
IDAHO
NEVADA
MONTANA
WYOMING
UTAH
ARIZONA
COLORADO
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
MICHIGAN
MICHIGAN
ILLINOIS
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
MD.
DEL.
N.J.
CONN.
R.I.
MASS.
VT.
N.H.
MAINE
1.43
1.29
1.27
1.58
1.29
1.15
1.81
1.85
1.97
2.22
2.21
2. 3
2.69
1.88
1.69
1.87

FIGURE 7.2
COST OF PRODUCTION OF SNG
($/MM Btu)

FIGURE 7.3

INTERMEDIATE BTU GAS PROCESS FLOW DIAGRAM

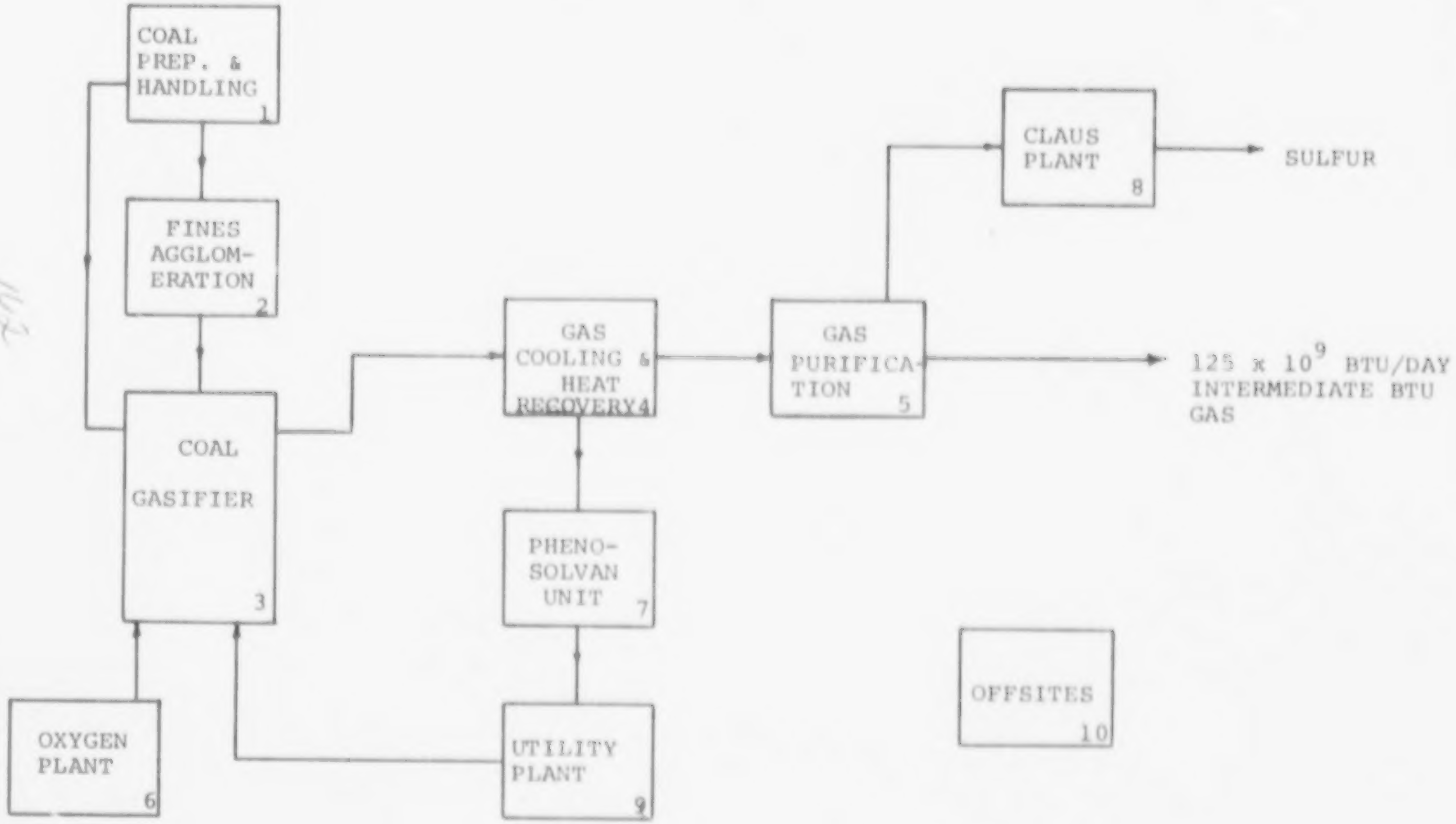

COAL PREP. & HANDLING 1
FINES AGGLOM- ERATION 2
COAL GASIFIER 3
GAS COOLING & HEAT RECOVERY 4
GAS PURIFICA- TION 5
OXYGEN PLANT 6
PHENO- SOLVAN UNIT 7
CLAUS PLANT 8
UTILITY PLANT 9
OFFSITES 10
SULFUR
125 x 10^9 BTU/DAY INTERMEDIATE BTU GAS

FIGURE 7.4

EFFECT OF CARBON CONTENT OF COAL ON INTERMEDIATE BTU GAS CAPITAL COST

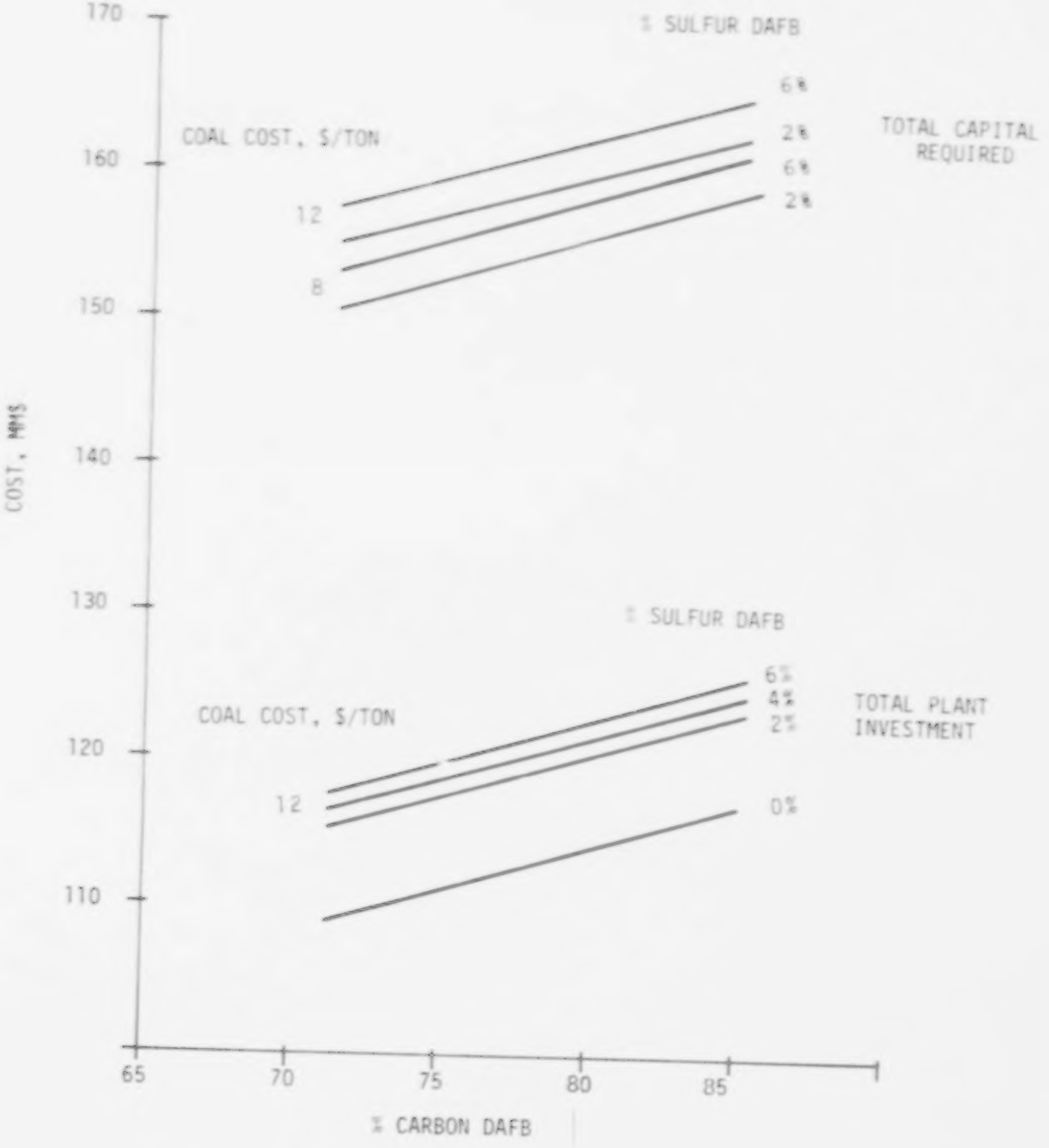


FIGURE 7.5

EFFECT OF CARBON CONTENT OF COAL ON INTERMEDIATE BTU GAS PRODUCTION COST

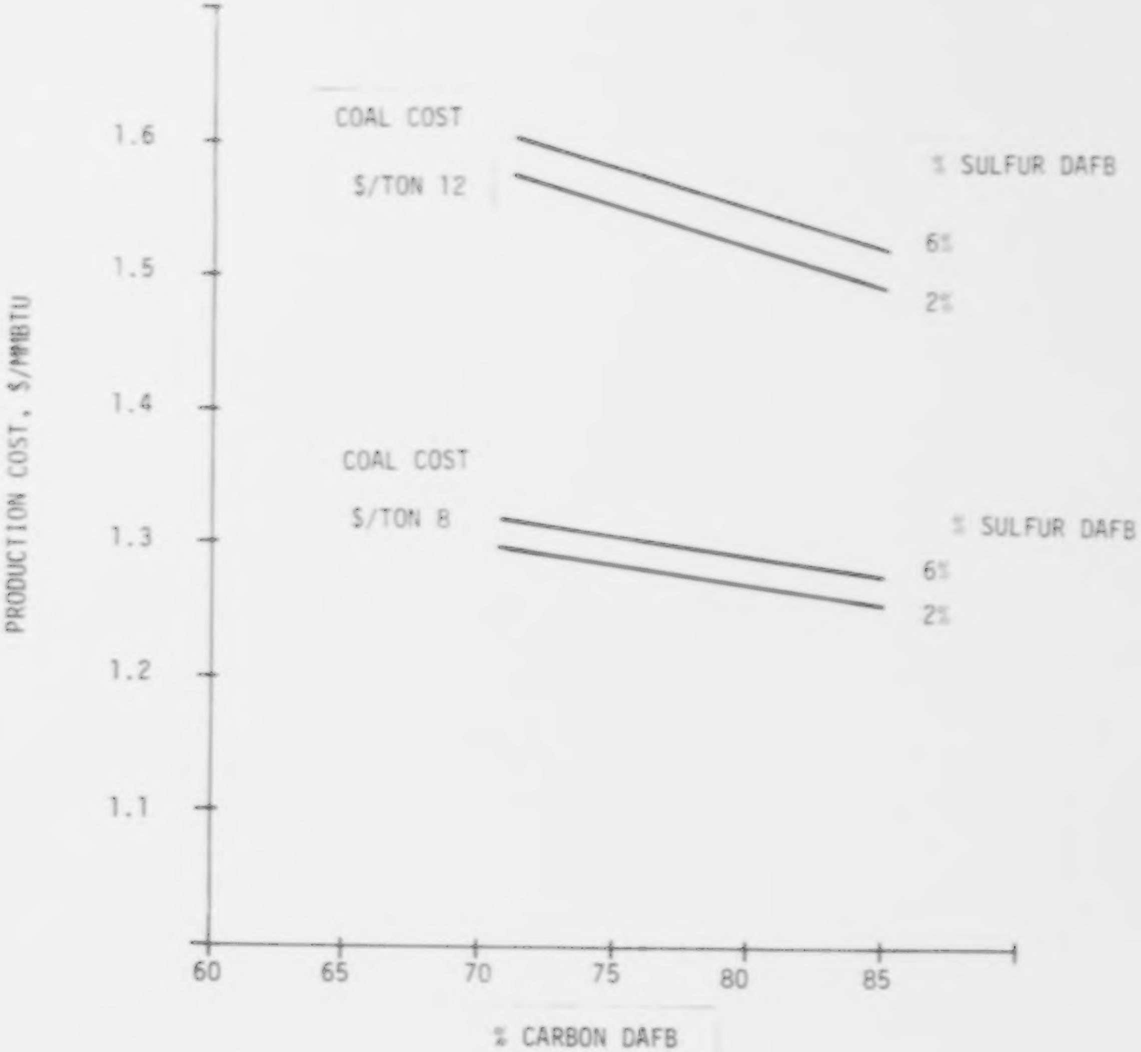


FIGURE 7.6

EFFECT OF LOCATION FACTOR ON INTERMEDIATE BTU GAS PRODUCTION COST

BITUMINOUS COAL: CARBON = 84% DAFB
SULFUR = 2% DAFB
ASH = 7%
H_2O = 6%

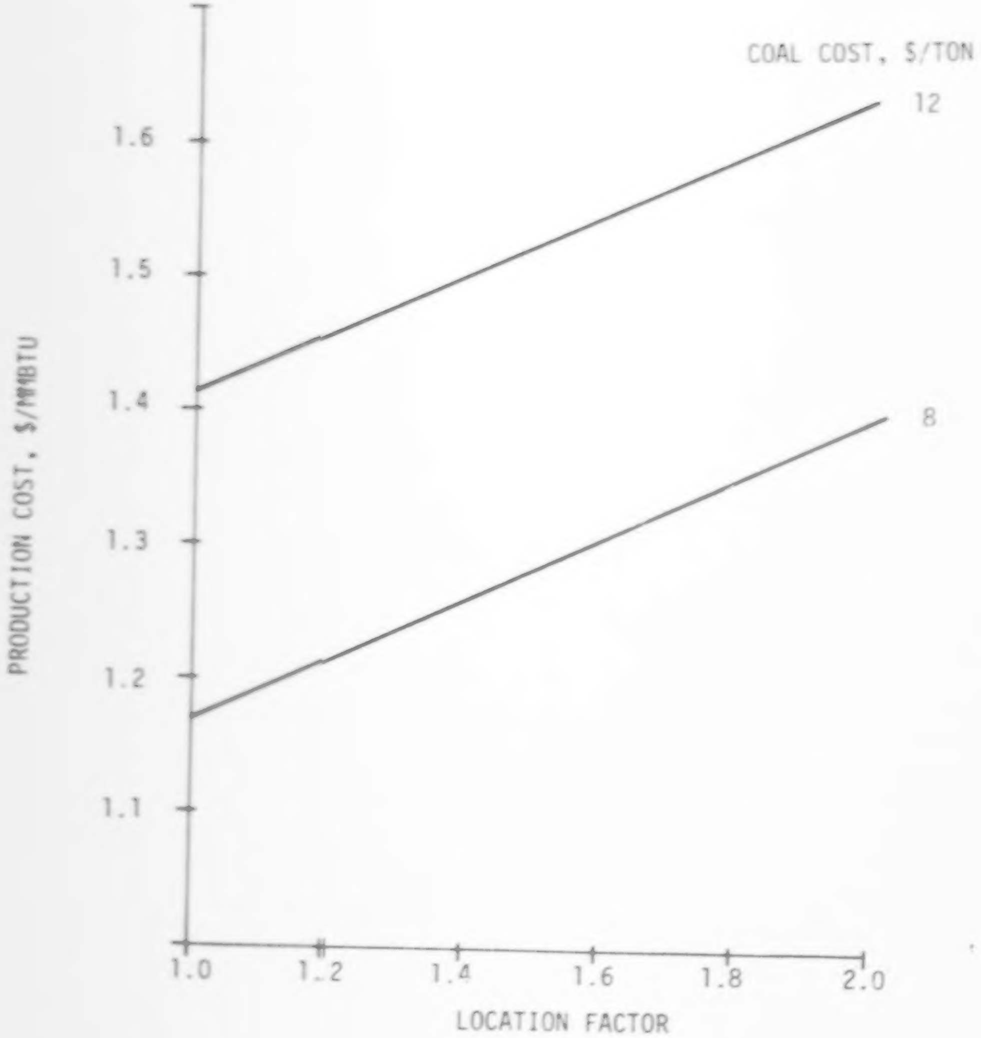


FIGURE 7.7

LOW BTU GAS PROCESS FLOW DIAGRAM

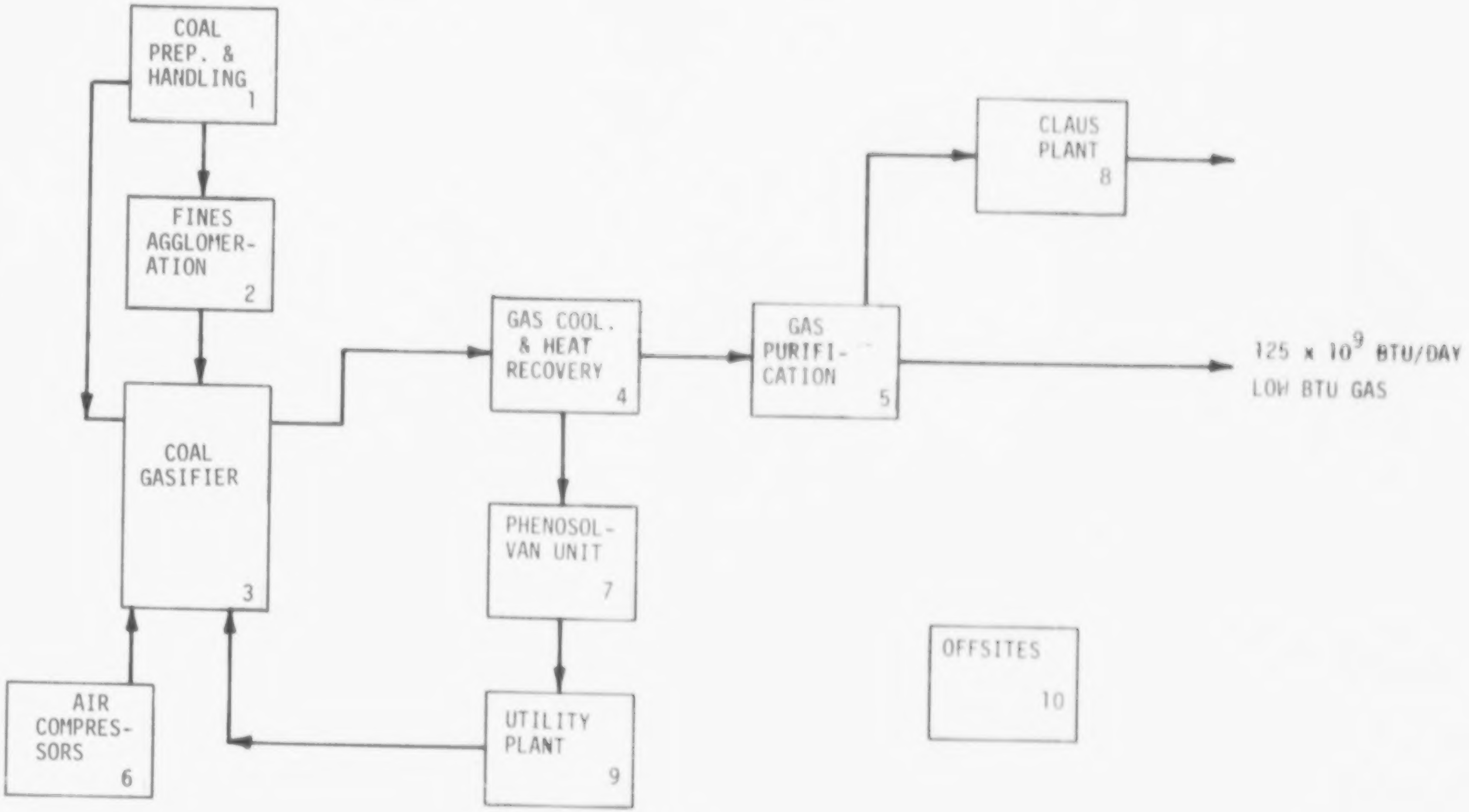

COAL PREP. & HANDLING 1
FINES AGGLOMERATION 2
COAL GASIFIER 3
GAS COOL. & HEAT RECOVERY 4
GAS PURIFICATION 5
AIR COMPRESSORS 6
PHENOSOLVAN UNIT 7
CLAUS PLANT 8
UTILITY PLANT 9
OFFSITES 10
125 x 10^9 BTU/DAY
LOW BTU GAS

FIGURE 7.8

EFFECT OF CARBON CONTENT OF COAL ON LOW BTU GAS

CAPITAL COST

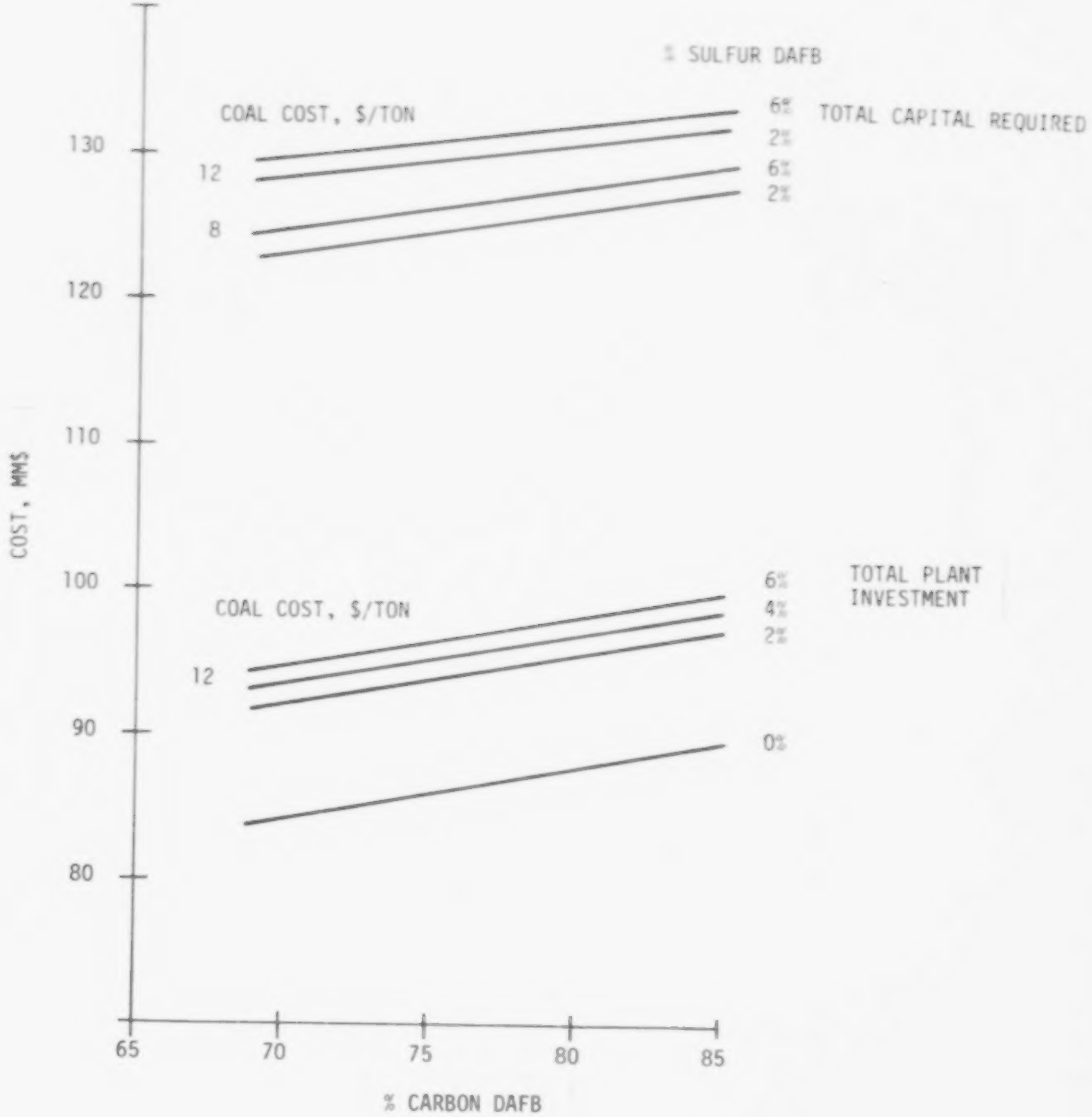


FIGURE 7.9
EFFECT OF CARBON CONTENT OF COAL ON
LOW BTU GAS PRODUCTION COST

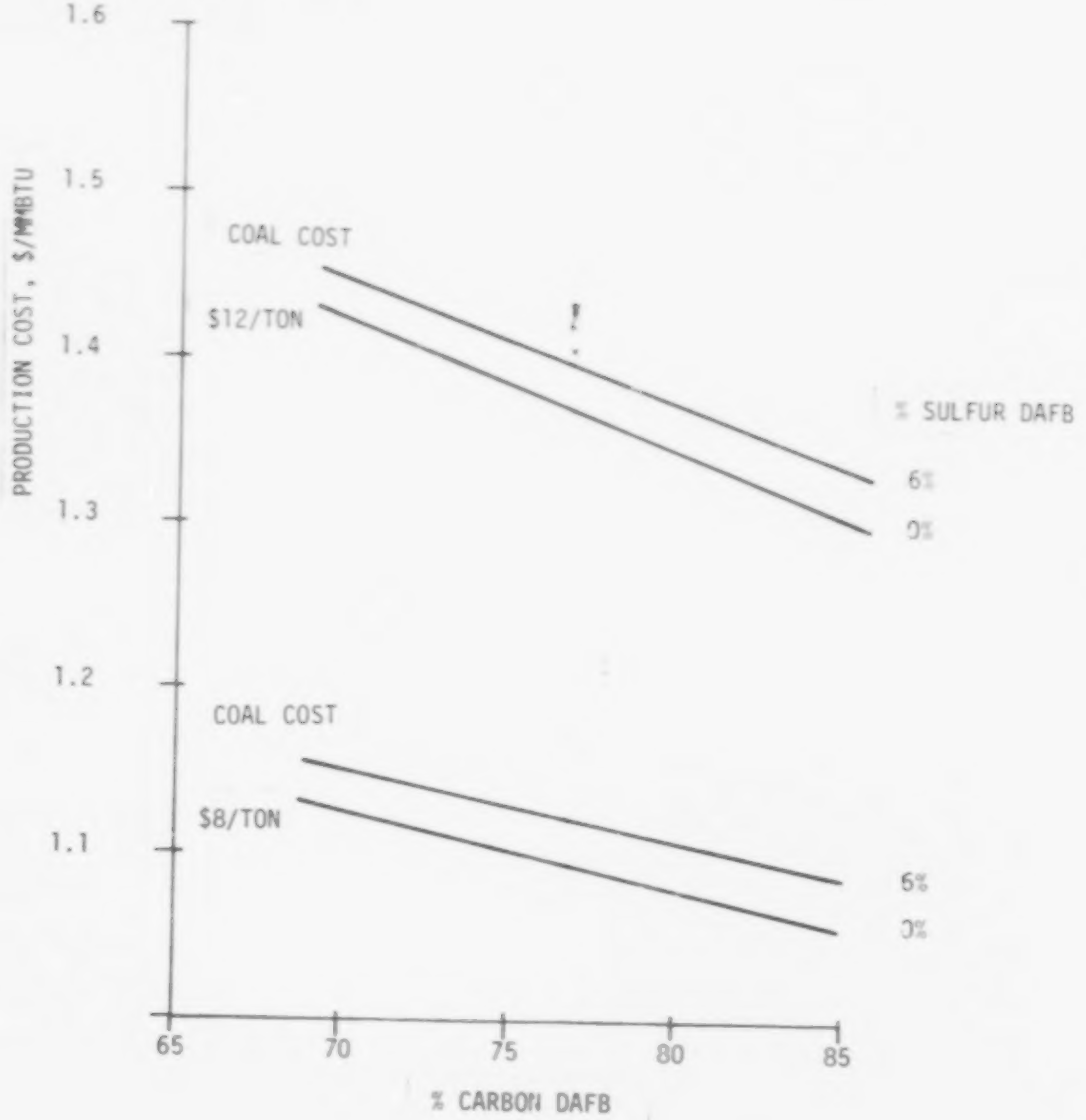
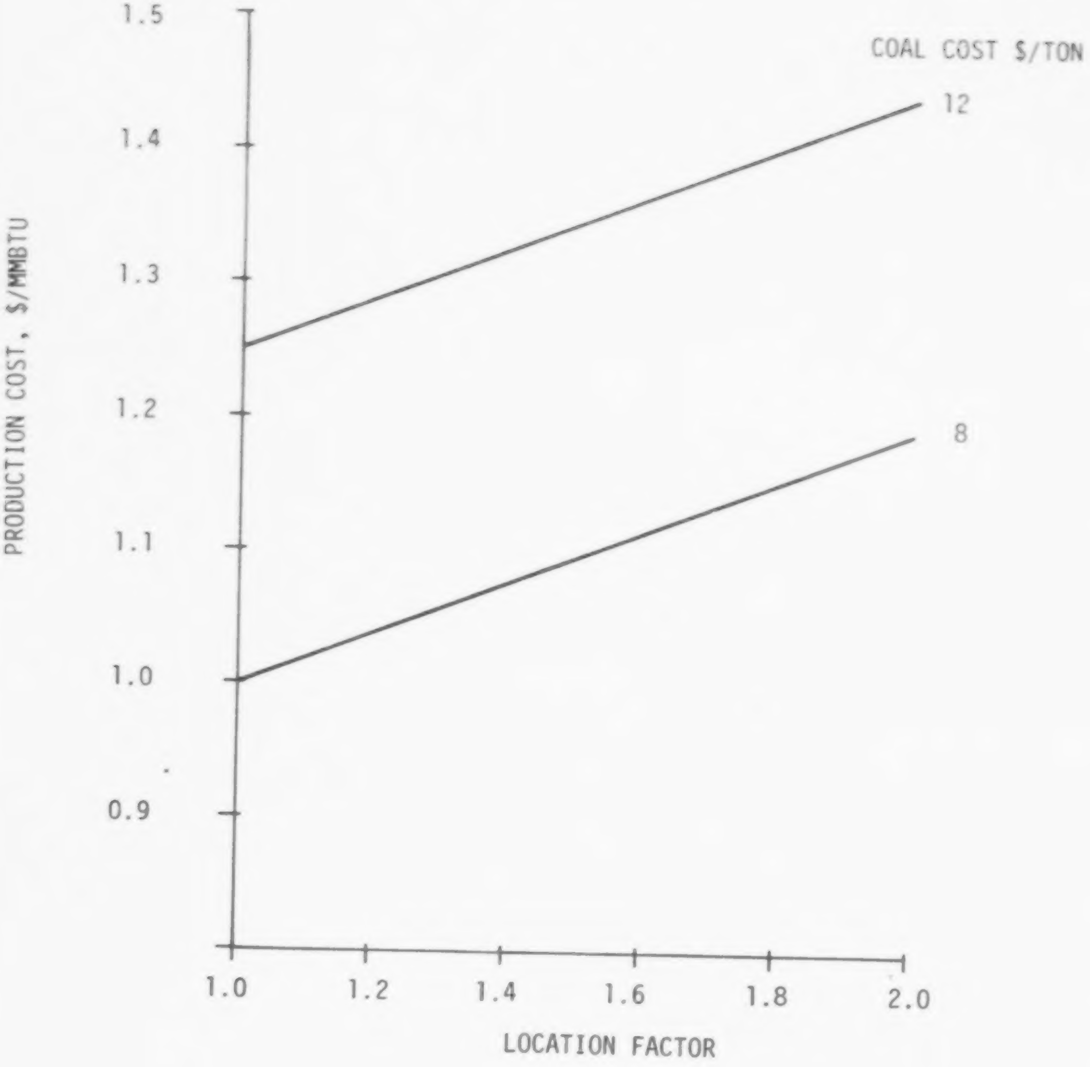


FIGURE 7.10

EFFECT OF LOCATION FACTOR ON LOW BTU GAS PRODUCTION COST

BITUMINOUS COAL: CARBON = 84%
SULFUR = 2%
ASH = 7%
H_2O = 6%



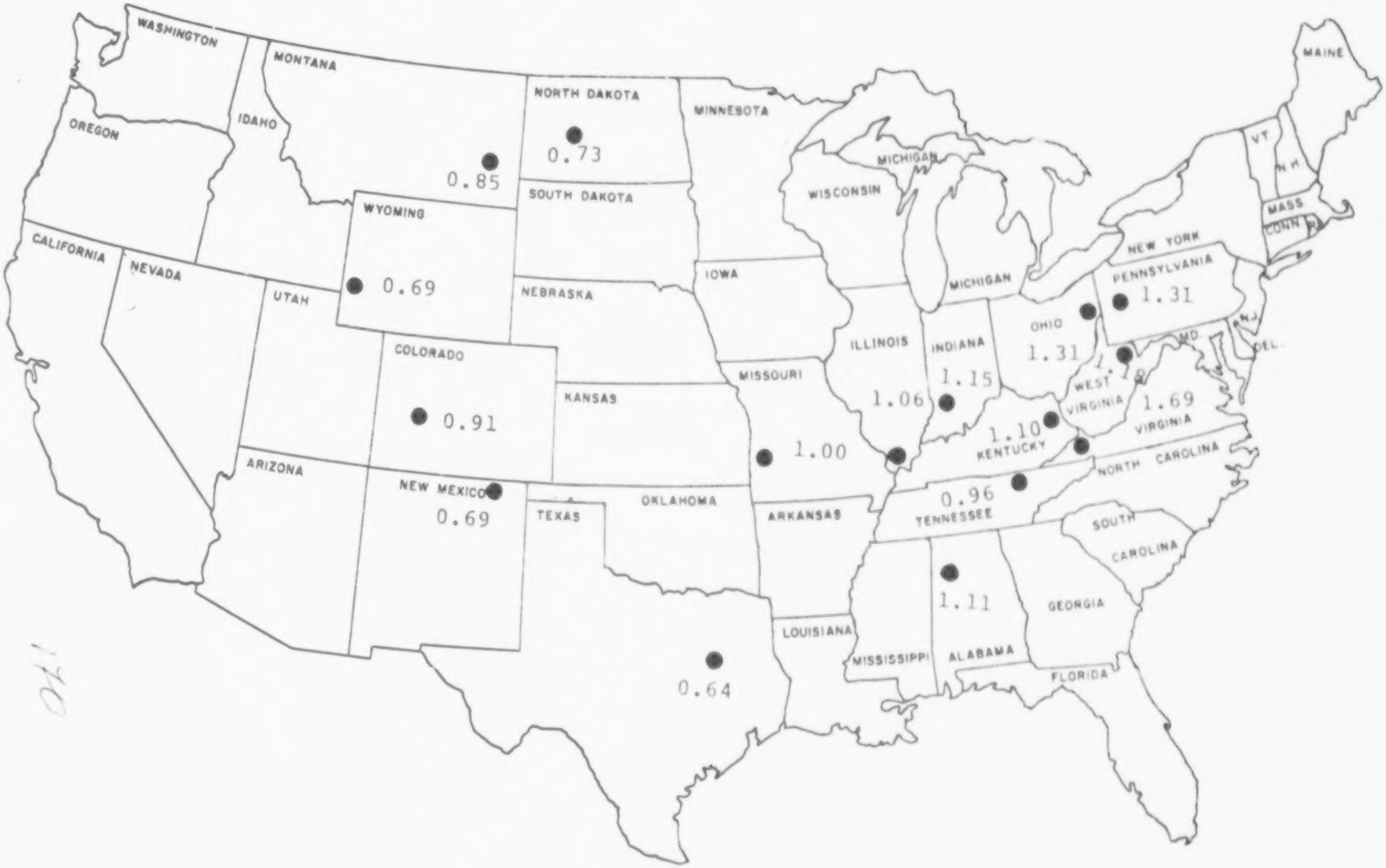

WASHINGTON
OREGON
CALIFORNIA
IDAHO
NEVADA
MONTANA
0.85
WYOMING
0.69
UTAH
ARIZONA
COLORADO
0.91
NEW MEXICO
0.69
NORTH DAKOTA
0.73
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
0.64
MINNESOTA
IOWA
MISSOURI
1.00
ARKANSAS
LOUISIANA
WISCONSIN
MICHIGAN
MICHIGAN
ILLINOIS
1.06
INDIANA
1.15
OHIO
1.31
KENTUCKY
1.10
TENNESSEE
0.96
MISSISSIPPI
ALABAMA
1.11
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
WEST VIRGINIA
1.18
VIRGINIA
1.69
PENNSYLVANIA
1.31
NEW YORK
MD.
DEL.
NJ
MAINE
VT.
N H
MASS
CONN

FIGURE 7.11
COST OF PRODUCTION OF SRC
($/MM Btu)

8. REFERENCES

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8. REFERENCES

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APPENDIX A

FPC FORM 67

FPC Form 67
Rev (6-70)

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME		PLANT NAME		REPORT FOR YEAR ENDED DECEMBER 31, 19 ____
COMPANY - PLANT CODE	PLANT CAPACITY - MW	STATE	COUNTY	POST OFFICE AND ZIP CODE

Schedule A - Fuel Quality

SECTION 1 - Plant Fuel Consumption Data

QUALITY REPORTED ON (Check one) :
☐ (B) ... "As burned" basis
☐ (R) ... "As received" basis

Report percent sulfur, ash, and moisture figures as weighted averages for the month to the nearest 0.1 percent (based on weight of fuel consumed). Report fuel quality and Btu values on "as burned" basis; if quality is only available on "as received" basis, it may be so reported. If fuel represents a blend of two or more types of coal or oil with distinctly different qualities, this should be described in a footnote.

		COAL					OIL			GAS		
LINE NO.	MONTH (a)	CONSUMPTION 1000 Tons (b)	BTU per Pound (c)	AVG. % SULFUR (d)	AVG. % ASH (e)	AVG. % MOISTURE (f)	CONSUMPTION 1000 Bbls (g)	BTU per Gal. (h)	AVG. % SULFUR (i)	CONSUMPTION 1000 Mcf. (j)	BTU per cu. ft. (k)	CHECK FOR FOOTNOTE* (l)
01	JAN.											
02	FEB.											
03	MAR.											
04	APR.											
05	MAY											
06	JUNE											
07	JULY											
08	AUG.											
09	SEP.											
10	OCT.											
11	NOV.											
12	DEC.											
13	YEAR											

* All footnotes should be shown on page 12.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME	COMPANY - PLANT CODE	REPORT FOR YEAR ENDED
PLANT NAME		DECEMBER 31, 19 ____

Schedule A - Fuel Quality (Cont'd)

Section 2 - Plant Fuel Source Data

LINE NO.		COAL		OIL			
				SOURCE			
	(a)	SOURCE (BUREAU OF MINES COAL DISTRICTS)* (b)	QUANTITY 1000 Tons (c)	SUPPLIER ** (d)	REFINERY OR PORT OF ENTRY *** (e)	QUANTITY 1000 Bbls (f)	CHECK FOR FOOTNOTE (g)****
14	SOURCE 1						
15	SOURCE 2						
16	SOURCE 3						
17	SOURCE 4						
18	SOURCE 5						
19	SOURCE 6						
20	SOURCE 7						
21	SOURCE 8						
22	ALL OTHER						

* List of Bureau of Mines Coal Districts is attached. If available, give name and location of mines (in footnote on page 12) supplying substantial portions of the coal used at the plant and the quantities supplied by each mine.

** If residual oil is delivered to a company-wide tank farm for distribution to more than one plant, explain in footnote.

*** Indicate refinery by "(R)" before refinery name; Port of entry by "(P)"; Other by "(O)". Explain "Other" in footnote.

**** All footnotes should be shown on page 12.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 _____

SCHEDULE B - OPERATIONAL DATA

A separate sheet (including Sections 1 and 2) should be prepared for each plant boiler.

01 **Section 1 - Fuel Consumption at Boiler No. ____________ ***

LINE NO.	MONTH (a)	COAL (1000 Tons) (b)	OIL (1000 Bbls) (c)	GAS (1000 Mcf) (d)	CHECK FOR FOOTNOTE** (e)
02	JANUARY				
03	FEBRUARY				
04	MARCH				
05	APRIL				
06	MAY				
07	JUNE				
08	JULY				
09	AUGUST				
10	SEPTEMBER				
11	OCTOBER				
12	NOVEMBER				
13	DECEMBER				
14	TOTAL YEAR				

15 **Section 2 - Boiler Operation During Year, Boiler No. ___________**

Enter as appropriate the following codes 1 thru 7 in columns (b), (c), (d), and (e), lines 16, 17 and 18; Actual hours of system peak need not be shown.

Boiler Operation	Code	Boiler Operation	Code
Continuous nominal full load	1	No-load hot standby	5
Less than full but over 75% load . . .	2	No-load cold standby	6
50% - 75% load	3	Other (explain in footnote, pg. 12) . .	7
Under 50% load	4		

LINE NO.	During Period of System (a)	WEEKDAYS		WEEKENDS ***		CHECK FOR FOOTNOTE ** (f)
		Average for consecutive four hours of highest output (Code only) (b)	Average for consecutive four hours of lowest output (Code only) (c)	Average for consecutive four hours of highest output (Code only) (d)	Average for consecutive four hours of lowest output (Code only) (e)	
16	WINTER PEAK WEEK					
17	SUMMER PEAK WEEK					
18	LOWEST POWER PERIOD WEEK					
19	TOTAL HOURS OF BOILER OPERATION DURING YEAR:					
20	BOILER CAPACITY FACTOR, AVERAGE DURING YEAR, PERCENT:					

---

* If fuel consumption is for a group of boilers served by a common fuel feeder, please indicate in footnote, line 14; List all boiler numbers sharing the same fuel feeder (__, __, __, __). Common fuel feeder may be shown on plant one-line diagram.

** All footnotes should be shown on page 12.

*** Midnight Friday to midnight Sunday.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME	
PLANT NAME	
COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19 ______

SCHEDULE B - OPERATIONAL DATA (Cont'd)

Section 3 - Flue Gas Cleaning Equipment

LINE NO.	(a)	BOILER NO. (b)	BOILER NO. (c)	BOILER NO. (d)	BOILER NO. (e)	CHECK FOR FOOTNOTE ** (f)
21	BOILER NUMBER					
	MECHANICAL SEPARATORS:					
22	TESTED EFFICIENCY					
23	DATE OF TEST (YEAR/MONTH/DAY)					
24	ESTIMATED EFFICIENCY AT ANNUAL OPERATING FACTOR (If no test during year)					
	ELECTROSTATIC OR COMBINATION MECHANICAL-ELECTRICAL PRECIPITATORS:					
25	TYPE (Code "E" for Electrostatic, or "C" for Combination)					
26	TOTAL HOURS FOR THE YEAR DURING WHICH ALL ELECTRICAL BUS SECTIONS ARE ENERGIZED AND WHILE BOILER IS OPERATING *					
27	TESTED EFFICIENCY					
28	DATE OF TEST (YEAR/MONTH/DAY)					
29	STATE NUMBER OF HOURS DURING YEAR WHEN PRECIPITATOR IS NOT FULLY OPERATIONAL WHILE BOILER IS OPERATING.					
30	ESTIMATED EFFICIENCY DURING PERIODS WHEN BOILER IS OPERATING BUT WHEN PRECIPITATOR IS NOT FULLY OPERATIONAL					
31	ESTIMATED EFFICIENCY AT ANNUAL OPERATING FACTOR (If no test during year) *					
	DESULFURIZATION SYSTEM: ***					
32	HOURS OF SERVICE DURING YEAR *					
33	TESTED EFFICIENCY					
34	DATE OF TEST (YEAR/MONTH/DAY)					
35	ESTIMATED EFFICIENCY AT ANNUAL OPERATING FACTOR (If no test during year)*					
	OTHER FLUE GAS CLEANING TYPE (Explain in footnote)					
36	HOURS IN SERVICE DURING YEAR*					

* Explain in footnote unusual operating conditions

** All footnotes should be shown on page 12.

*** When operational

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ____

SCHEDULE C - Disposal of Products Collected from Combustion Cycle at Plant

LINE NO.	(a)	LIMESTONE (b)	DOLOMITE (c)	OTHER ** (d)	CHECK FOR FOOTNOTE (e) ***
01	AMOUNT OF ADDITIVES USED (1000 tons)*				

LINE NO.	PRODUCT (a)	QUANTITIES (1000 tons)*						CHECK FOR FOOTNOTE (h) ***
		TOTAL COLLECTED **** (b)	SOLD (c)	PAID DISPOSAL (d)	LAND FILL (e)	WATER DISPOSAL (f)	OTHER DISPOSAL (g)	
02	FLYASH							
03	BOTTOM ASH							
04	ELEMENTAL SULFUR							
05	SULFURIC ACID *****							
06	SULFUR DIOXIDE							
07	OTHER SULFUR PRODUCTS**							
08	OTHER PRODUCTS **							

* Report all quantities to nearest 0.1 thousand tons.

** Specify in footnote

*** All footnotes should be shown on page 12.

**** Total of products collected (column "b") should approximate the sum of columns "c" through "g".

***** Enter purity of acid: ______ % by weight.

SCHEDULE D - Air Quality Control, Plant Operation and Maintenance Expenses

LINE NO.	CHARGED TO: (a)	AMOUNT ($1000) (b)	CHECK FOR FOOTNOTE 1/ (c)
09	FLYASH COLLECTION AND DISPOSAL	$	
10	BOTTOM ASH COLLECTION AND DISPOSAL		
11	SULFUR AND SULFUR PRODUCT COLLECTION AND DISPOSAL		
12	COLLECTION AND DISPOSAL OF OTHER PRODUCTS FROM FLUE GAS (SPECIFY IN FOOTNOTE)		
13	OTHER AIR QUALITY CONTROL EXPENSES (SPECIFY IN FOOTNOTE)		
14	TOTAL AIR QUALITY CONTROL EXPENSE (TOTAL OF LINES 09 THROUGH 13)		
	REVENUES FROM AIR QUALITY CONTROL OPERATIONS:		
15	SALES OF FLYASH (IF SOLD AS FLYASH)		
16	SALES OF BOTTOM ASH (IF SOLD AS BOTTOM ASH)		
17	SALES OF FLYASH AND BOTTOM ASH (IF SOLD INTERMINGLED)		
18	SALES OF SULFUR AND SULFUR PRODUCTS		
19	OTHER REVENUES FROM AIR QUALITY CONTROL OPERATIONS (SPECIFY IN FOOTNOTE)		
20	TOTAL BY-PRODUCT SALES REVENUE FROM AIR QUALITY CONTROL OPERATIONS (TOTAL OF LINES 15 THROUGH 19)		

1/ All footnotes should be shown on page 12.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ____

SCHEDULE E - Equipment (Design Parameters)

PLEASE CIRCLE THE APPROPRIATE NUMBER:

(1) Regular Plant Report
(2) Placed in Operation during year
(3) Altered during year
(4) Not previously reported
(5) Amended report

LINE NO.	Section 1 - Boiler Data (a)	BOILER NO. (b)	BOILER NO. (c)	BOILER NO. (d)	BOILER NO. (e)	CHECK FOR FOOTNOTE (f)**
01	BOILER NUMBER(S)					
02	SERVED BY STACK NUMBER					
03	RELATED TO GENERATOR NUMBER					
04	BOILER MANUFACTURER (Code as shown below)*					
05	YEAR BOILER PLACED IN SERVICE					
06	ASSOCIATED TURBO-GENERATING CAPACITY (Megawatts)					
07	MAXIMUM CONTINUOUS STEAM CAPACITY (Thousand pounds/hour)					
	DESIGN FUEL CONSUMPTION: 100% RATING					
08	COAL (Tons/hour)					
09	RESIDUAL OIL (Barrels/hour)					
10	GAS (Thousand cubic feet/hour)					
	PERCENT BOILER EFFICIENCY					
11	AT 100% LOAD					
12	AT 75% LOAD					
13	AT 50% LOAD					
	AIR FLOW AT 100% LOAD					
14	TOTAL AIR, STANDARD CUBIC FEET/MINUTE (Incl. Excess Air)					
15	PERCENT EXCESS AIR USED					
16	WET OR DRY BOTTOM - (Code as "Wet" or "Dry")(For Coal only)					
17	FLYASH REINJECTION - (Code "Yes" or "No")					
18	TYPE OF FIRING (Code as shown below)***					

* BOILER MANUFACTURERS:

B&W - The Babcock & Wilcox Co.
CE - Combustion Engineering, Inc.
ERIG - Erie City Iron Works
FW - Foster Wheeler Corp.
RILY - Riley Stoker Corp.
VOGT - Henry Vogt Machine Co., Inc.
OTHE - Other (Specify in footnote)

** All footnotes should be shown on page 12.

*** TYPE OF FIRING (Where applicable, use more than one code):

PCFR - Pulverized Coal: Front Firing
PCOP - Pulverized Coal: Opposed Firing
PCTA - Pulverized Coal: Tangential Firing
CYCL - Cyclone
SPRE - Spreader Stoker
OSTO - Other Stoker
FLUI - Fluidized Bed
RFRO - Residual Oil: Front Firing
ROPP - Residual Oil: Opposed Firing
RTAN - Residual Oil: Tangential Firing
GFRO - Gas: Front Firing
GOPP - Gas: Opposed Firing
GTAN - Gas: Tangential Firing
OTHE - Other (Specify in footnote)

Sheet ____

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ______

SCHEDULE E - Equipment (Design Parameters) - Continued

Section 2 - Flue Gas Cleaning Equipment Data

LINE NO.	(a)	BOILER NO. (b)	BOILER NO. (c)	BOILER NO. (d)	BOILER NO. (e)	CHECK FOR FOOTNOTE (f) 1/
	BOILER NUMBERS (Enter same Boiler Numbers as indicated on page 9, line 01)					
	FLUE GAS CLEANING EQUIPMENT MECHANICAL COLLECTORS					
19	TYPE (Code as shown below)*					
20	DESIGN EFFICIENCY (Percent)					
21	MASS EMISSION RATE (Pounds per hour)**					
22	YEAR PLACED IN SERVICE					
23	INSTALLED COST (Thousands of dollars)***........					
24	MANUFACTURER (Code as shown below)****					
	ELECTROSTATIC AND COMBINATION MECHANICAL-ELECTRICAL PRECIPITATORS					
25	TYPE (Code as "E" or "C")					
26	DESIGN EFFICIENCY (Percent)					
27	MASS EMISSION RATE (Pounds per hour)**					
28	YEAR PLACED IN SERVICE					
29	INSTALLED COST (Thousands of dollars)***........					
30	MANUFACTURER (Code as shown below)****					
	DESULFURIZATION SYSTEM					
31	TYPE (Indicate by footnote).....................					
32	DESIGN EFFICIENCY (Percent)					
33	MASS EMISSION RATE (Pounds per hour)**..........					
34	YEAR PLACED IN SERVICE					
35	INSTALLED COST (Thousands of dollars)***					
36	MANUFACTURER (Specify in footnote)					
	OTHER FLUE GAS CLEANING EQUIPMENT					
37	TYPE (Indicate by footnote).....................					
38	DESIGN EFFICIENCY (Percent)					
39	MASS EMISSION RATE (Pounds per hour)**					
40	YEAR PLACED IN SERVICE					
41	INSTALLED COST (Thousands of dollars)***........					
42	MANUFACTURER (Specify in footnote)					

1/All footnotes should be shown on page 12.

* Mechanical Collectors - Type (If more than one type is used in a series, indicate all applicable codes and explain in footnote).

GRAV - Gravitational or baffled chamber
SCTA - Single cyclone-Conventional reverse flow, tangential inlet
SCAX - Single cyclone-Conventional reverse flow, axial inlet
MCTA - Multiple cyclones-Conventional reverse flow; tangential inlet.
MCAX - Multiple cyclones-Conventional reverse flow; axial inlet

CYCL - Straight-through-flow cyclones
IMPE - Impeller collector
VENT - Wet collector: Venturi
WETC - Wet Collector: Other (Specify in footnote)
BAGH - Baghouse (Fabric Collector)
OTHE - Other (Specify in footnote)

** Pounds per hour = $\frac{\text{Grains/Actual Cu.Ft./} \times \text{/Actual Cu.Ft.Vol./Hr./}}{\text{7000/Grains/Pound}}$

*** See Instruction 12, page 8.

**** Flue Gas Cleaning Equipment Manufacturers (See page 11 for Codes)

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Rev. (6-70)

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART I - AIR QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19 ____

SCHEDULE E - Equipment (Design Parameters) - Continued

Section 3 - Stack Data

LINE NO.	(a)	STACK NUMBER (b)	STACK NUMBER (c)	STACK NUMBER (d)	STACK NUMBER (e)	CHECK FOR FOOTNOTE* (f)
43	STACK NUMBERS					
44	INSTALLED COST (Thousands of dollars)(Instruction 12, page 8)					
45	STACK HEIGHT (Feet above Ground Elevation)					
46	INSIDE DIAMETER OF FLUE AT TOP (inches)					
	FLUE GAS RATE (CUBIC FEET/MINUTE)					
47	AT 100% LOAD					
48	AT 75% LOAD					
49	AT 50% LOAD					
	EXIT GAS TEMPERATURE (DEGREES FARENHEIT)					
50	AT 100% LOAD					
51	AT 75% LOAD					
52	AT 50% LOAD					
	EXIT GAS VELOCITY (FEET/SECOND)					
53	AT 100% LOAD					
54	AT 75% LOAD					
55	AT 50% LOAD					
56	DISTANCE TO NEXT STACK, CENTER TO CENTER (FEET)**					
57	ORIENTATION OF LINE OF STACKS - DEGREES CLOCKWISE FROM TRUE NORTH**					

* All footnotes should be shown on page 12.

** Show position of stacks by stack number to correspond with the identification in line 43. Enter true north on the diagram.

Stacks Orientation Diagram:

FLUE GAS CLEANING EQUIP. MANUFACTURERS (See pg. 10)

AAFC - American Air Filter Co., Inc.
AMST - American Standard, Inc.
BELC - Belco Pollution Control Corp.
BUEL - Buell Engineering Co., Inc.
DUCO - The Ducon Co., Inc.
FIKL - Fischer-Klosterman, Inc.
FULL - Fuller Co., Draco Products
KIRK - Kirk & Blum Manufacturing Co.
KOPP - Koppers Co., Inc.
PPCI - Precipitair Pollution Control, Inc.
PAOA - Precipitation Associates of America, Inc.
PLVR - Pulverizing Machinery Division
COTT - Research-Cottrell, Inc.
SVRS - Seversky Electronatom Corp.
UOP - UOP Air Correction Division
TORI - The Torit Corp.
WEST - Western Precipitation Division
WHEE - Wheelabrator Corp.
ZURN - Zurn Industries, Inc.
OTHE - Other (Specify in footnote)

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA
(Applicable to Nuclear and Fossil Fueled Steam-Electric Plants)

COMPANY NAME			REPORT FOR YEAR ENDED DECEMBER 31, 19____
PLANT NAME			COMPANY - PLANT CODE
PLANT CAPACITY - MW	STATE	COUNTY	POST OFFICE AND ZIP CODE

SCHEDULE A - OPERATIONAL DATA

Section 1 - Average Annual Cooling Water Use of Plant - CFS

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
01	AVERAGE RATE OF WITHDRAWAL FROM WATER BODY DURING YEAR		
02	AVERAGE RATE OF DISCHARGE TO WATER BODY DURING YEAR		
03	AVERAGE RATE OF CONSUMPTION DURING YEAR		

Section 2 - Maximum Water Temperatures and Average Stream Flows During Months of Winter and Summer System Peak Power Loads

	WINTER PEAK LOAD MONTH ________ **			SUMMER PEAK LOAD MONTH ________ **			
LINE NO.	MAXIMUM TEMPERATURE °F		MONTHLY AVERAGE FLOW IN RECEIVING WATER BODY, CFS	MAXIMUM TEMPERATURE °F		MONTHLY AVERAGE FLOW IN RECEIVING WATER BODY, CFS	CHECK FOR FOOTNOTE *
	AT DIVERSION (a)	AT OUTFALL (b)	(c)	AT DIVERSION (d)	AT OUTFALL (e)	(f)	(g)
04							

Section 3 - Amount of Chemicals used During the Year

LINE NO.	(a)	PHOSPHATE LBS. (b)	CAUSTIC SODA LBS. (c)	HYDRAZINE GALS. (d)	LIME LBS. (e)	ALUM. LBS. (f)	CHLORINE LBS. (g)	OTHER (h)	CHECK FOR FOOTNOTE * (i)
05	COOLING WATER								
06	BOILER WATER MAKEUP								

SCHEDULE B - OPERATION AND MAINTENANCE EXPENSES, $1,000

Section 1 - Cooling Water Operation at Plant

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
07	ANNUAL OPERATION AND MAINTENANCE EXPENSES		
08	ANNUAL COST OF CHEMICAL ADDITIVES		

Section 2 - Boiler Water Makeup and Boiler Blowdown Treatment

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
09	ANNUAL OPERATION AND MAINTENANCE EXPENSES		
10	ANNUAL COST OF CHEMICAL ADDITIVES		

* All footnotes should be shown on page 20.
** Specify month.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19____

SCHEDULE C - WATER USE AUTHORITY AND LIMITING CRITERIA

LINE NO.	(a)	(b)	CHECK FOR FOOTNOTE * (c)
01	ISSUING AUTHORITIES OF LICENSES OR PERMITS: COUNTY, STATE, FEDERAL, OR OTHER. LIST AND DESCRIBE AUTHORITIES IN FOOTNOTE.		
02	FREQUENCY OF TEMPERATURE MONITORING OF COOLING WATER EFFLUENT: CONTINUOUSLY (C), HOURLY (H), DAILY (D), OR OTHER (O). FOOTNOTE AND EXPLAIN IF OTHER.		
03	DISTANCE MIXING ZONE EXTENDS DOWNSTREAM, FT.		
04	DISTANCE MIXING ZONE EXTENDS FROM SHORE, FT.		

LINE NO.	(a)	SUMMER (b)	WINTER (c)	CHECK FOR FOOTNOTE * (d)
	MAXIMUM ALLOWABLE TEMPERATURE RISE OF COOLING WATER (°F)			
05	AT OUTFALL TO RECEIVING WATER BODY			
06	AT LIMITS OF DEFINED MIXING ZONE			
	MAXIMUM ALLOWABLE TEMPERATURE OF COOLING WATER (°F)			
07	AT OUTFALL TO RECEIVING WATER BODY			
08	AT LIMITS OF DEFINED MIXING ZONE			

SCHEDULE D - COOLING FACILITIES

SECTION 1 - GENERAL DESIGN DATA

LINE NO.	(a)	(b)	(c)	(d)	(e)	CHECK FOR FOOTNOTE * (f)
09	GENERATING UNIT IDENTIFICATION NUMBER					
10	RATED GENERATING CAPACITY, MW					
11	TYPE COOLING: ONCE-THROUGH, FRESH (OTF): ONCE-THROUGH, SALINE (OTS): COOLING POND (CP): WET COOLING TOWER (WCT): DRY COOLING TOWER (DCT): COMBINATION (CB). FOOTNOTE AND EXPLAIN COMBINATIONS.					
12	YEAR COOLING FACILITIES INSTALLED					
13	DESIGNED TEMPERATURE RISE ACROSS THE CONDENSER, °F					
14	DESIGNED RATE OF FLOW THROUGH THE CONDENSER, CFS					

* ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19____

SCHEDULE D - COOLING FACILITIES - Continued

LINE NO.	SECTION 2 - ONCE THROUGH COOLING					CHECK FOR FOOTNOTE *
	(a)	(b)	(c)	(d)	(e)	(f)
15	DESIGNED RATE OF WITHDRAWL AT FULL LOAD, CFS					
16	INTAKE LOCATIONS: 1/ DIRECTION FROM CENTER OF PLANT, DEGREES					
17	DISTANCE FROM CENTER OF PLANT, FT.					
18	DISTANCE FROM SHORE, FT.					
19	AVERAGE DISTANCE BELOW WATER SURFACE, FT.					
20	OUTFALL LOCATIONS: 1/ DIRECTION FROM CENTER OF PLANT, DEGREES					
21	DISTANCE FROM CENTER OF PLANT, FT.					
22	DISTANCE FROM SHORE, FT.					
23	AVERAGE DISTANCE BELOW WATER SURFACE, FT.					
24	ARE DIFFUSERS USED? FOOTNOTE AND DESCRIBE IF "YES."					
25	INSTALLED COSTS, $1,000 **					

LINE NO.	SECTION 3 - COOLING PONDS					CHECK FOR FOOTNOTE *
	(a)	(b)	(c)	(d)	(e)	(f)
26	TOTAL SURFACE AREA, ACRES					
27	TOTAL VOLUME, ACRE-FEET					
28	INSTALLED COSTS, $1,000 **					

LINE NO.	SECTION 4 - COOLING TOWERS					CHECK FOR FOOTNOTE *
	(a)	(b)	(c)	(d)	(e)	(f)
29	TYPE DRAFT-MECHANICAL (M), NATURAL (N)					
30	LENGTH, IF APPLICABLE, FEET					
31	WIDTH OR DIAMETER AT BASE, FEET					
32	HEIGHT, FEET					
33	WATER COOLING RANGE, °F					
34	INSTALLED COSTS, $1,000 **					

1/ ALTHOUGH NOT REQUIRED, A SKETCH SHOWING THE LAYOUT OF THE COOLING SYSTEM IS DESIRABLE.

* ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.

** See instruction 3, Schedule D, page 15.

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA

COMPANY NAME

PLANT NAME

COMPANY - PLANT CODE

REPORT FOR YEAR ENDED DECEMBER 31, 19____

SCHEDULE E - COOLING WATER SUPPLY

SECTION 1 - ONCE THROUGH COOLING

LINE NO.	SOURCE(S) OF WATER (a)	7-DAY, 10 YEAR DEPENDABLE FLOW CFS (b)	AVERAGE FLOW CFS (c)	GENERATING UNITS SERVED				CHECK FOR FOOTNOTE * (h)
				NO (d)	NO (e)	NO (f)	NO (g)	
01								
02								
03								

FOOTNOTE AND EXPLAIN ANY DISCHARGE INTO A DIFFERENT BODY OF WATER, AND WHEN DISCHARGE IS OTHER THAN DOWNSTREAM FROM WATER INTAKE LOCATION.

SECTION 2 - COOLING PONDS

LINE NO.	SOURCE(S) OF WATER (a)	7-DAY, 10 YEAR DEPENDABLE FLOW CFS (b)	AVERAGE FLOW CFS (c)	GENERATING UNITS SERVED				CHECK FOR FOOTNOTE * (h)
				NO (d)	NO (e)	NO (f)	NO (g)	
04								
05								
06								
07	PERIOD OF YEAR POND IS USED FOR COOLING							
08	OTHER USES OF POND							

SECTION 3 - COOLING TOWERS

LINE NO.	TOWER NO. (a)	SOURCE(S) OF MAKEUP WATER (b)	PERIOD OF YEAR USED FOR COOLING (c)	LOCATION OF BLOWDOWN DISCHARGE (d)	GENERATING UNITS SERVED				CHECK FOR FOOTNOTE * (i)
					NO (e)	NO (f)	NO (g)	NO (h)	
09									
10									
11									
12									
13									

* ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.

FPC Form 67
Rev (7-70)

Sheet ______

STEAM-ELECTRIC PLANT AIR AND WATER QUALITY CONTROL DATA
PART II - WATER QUALITY CONTROL DATA

COMPANY NAME	
PLANT NAME	
COMPANY - PLANT CODE	REPORT FOR YEAR ENDED DECEMBER 31, 19____

SCHEDULE F - WATER TREATMENT

SECTION 1 - SETTLING PONDS FOR BOILER WATER BLOWDOWN

LINE NO.	(a)	EVACUATION PROCEDURE AND FREQUENCY OF CLEANING		ESTIMATED		DISCHARGE VOLUME CU. FT. PER YR. (f)	NAME OF WATER BODY RECEIVING THE DISCHARGE (g)	CHECK FOR FOOTNOTE * (h)
		METHOD (b)	(TIMES PER YEAR) (c)	P^H (d)	SUSPENDED SOLIDS PPM (e)			
01	FIRST POND							
02	SECOND POND							

SECTION 2 - SETTLING PONDS FOR BOTTOM ASH

LINE NO.	(a)	EVACUATION PROCEDURE AND FREQUENCY OF CLEANING		ESTIMATED		DISCHARGE VOLUME CU. FT. PER YR. (f)	NAME OF WATER BODY RECEIVING THE DISCHARGE (g)	CHECK FOR FOOTNOTE * (h)
		METHOD (b)	(TIMES PER YEAR) (c)	P^H (d)	SUSPENDED SOLIDS PPM (e)			
03	FIRST POND							
04	SECOND POND							

LINE NO.	(a)	SOURCE OF SLUICING AND CLEANING WATER (b)	AMOUNT OF ASH TREATED TONS PER YEAR (c)	CHECK FOR FOOTNOTE * (d)
05	FIRST POND			
06	SECOND POND			

SECTION 3 - PROVISIONS FOR PLANT SEWAGE DISPOSAL

LINE NO.	(a)	CODE (b)	CHECK FOR FOOTNOTE * (c)
07	CODE FOR PUBLIC SEWER (PS), SEPTIC TANK (ST) SURFACE WATER BODY (SW), OR OTHER (OT). FOOTNOTE IF OTHER AND EXPLAIN.		

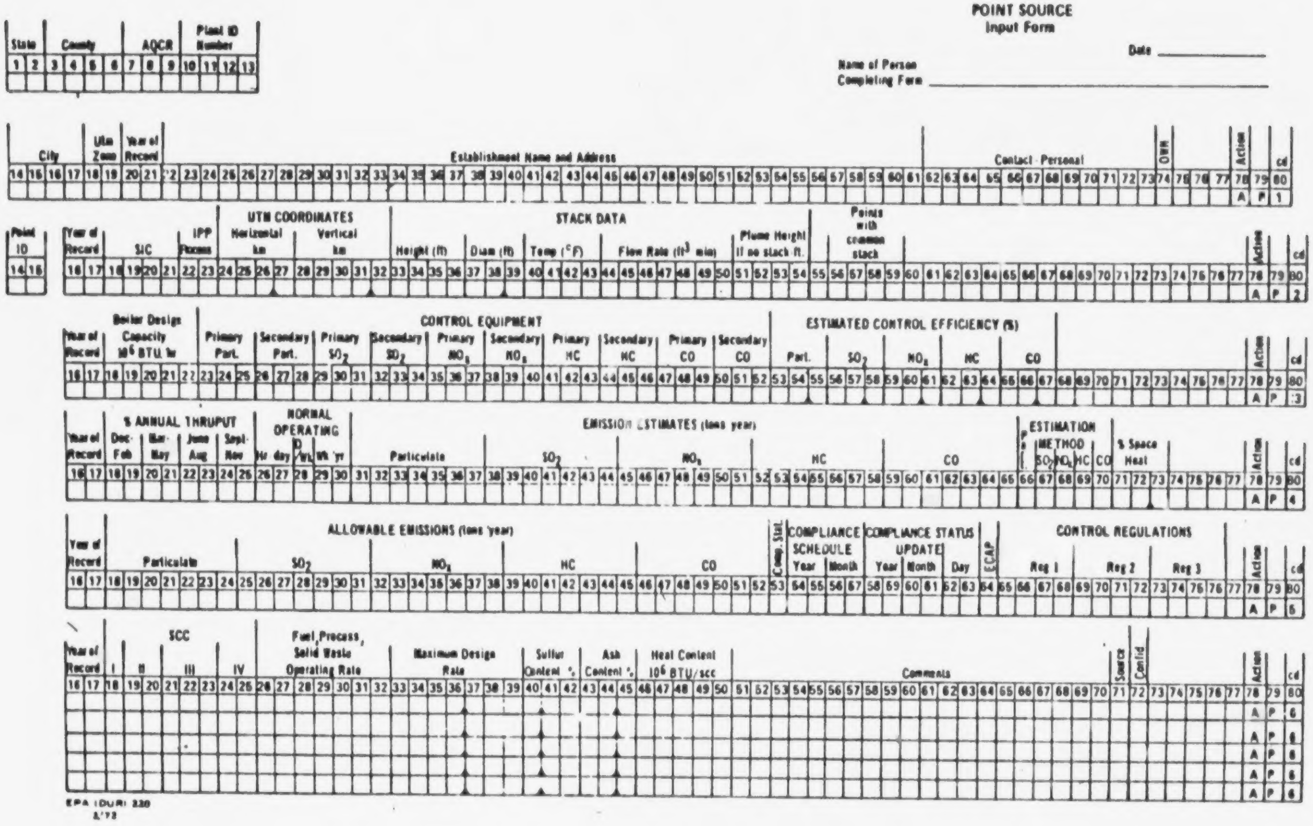
LINE NO.	EFFLUENT TREATMENT DESIGN: (a)	BOD PPM (b)	P^H (c)	PHOSPHATES PMM (d)	OTHER (e)	CHECK FOR FOOTNOTE * (f)
08	BEFORE TREATMENT					
09	AFTER TREATMENT					
10	WATER BODY RECEIVING THE DISCHARGE					

* ALL FOOTNOTES SHOULD BE SHOWN ON PAGE 20.

APPENDIX B

NEDS DATA INPUT FORM FOR INDUSTRIAL PLANTS

NEDS DATA INPUT FORM FOR INDUSTRIAL PLANTS.



POINT SOURCE
Input Form

Date ______

Name of Person
Completing Form ______

State | County | AQCR | Plant ID Number

City | Utm Zone | Year of Record | Establishment Name and Address | Contact - Personal | OWN | Action | cd
A P 1

Point ID | Year of Record | SIC | IPP Process | UTM COORDINATES: Horizontal km, Vertical km | STACK DATA: Height (ft), Diam (ft), Temp (°F), Flow Rate (ft³ min), Plume Height if no stack ft. | Points with common stack | Action | cd
A P 2

Year of Record | Boiler Design Capacity 10⁶ BTU hr | CONTROL EQUIPMENT: Primary Part., Secondary Part., Primary SO₂, Secondary SO₂, Primary NOₓ, Secondary NOₓ, Primary HC, Secondary HC, Primary CO, Secondary CO | ESTIMATED CONTROL EFFICIENCY (%): Part., SO₂, NOₓ, HC, CO | Action | cd
A P 3

Year of Record | % ANNUAL THRUPUT: Dec-Feb, Mar-May, June-Aug, Sept-Nov | NORMAL OPERATING: Hr day, D/Wk, Wk yr | EMISSION ESTIMATES (tons year): Particulate, SO₂, NOₓ, HC, CO | P s | ESTIMATION METHOD: SO₂, NOₓ, HC, CO | % Space Heat | Action | cd
A P 4

Year of Record | ALLOWABLE EMISSIONS (tons year): Particulate, SO₂, NOₓ, HC, CO | Comp. Stat. | COMPLIANCE SCHEDULE: Year, Month | COMPLIANCE STATUS UPDATE: Year, Month, Day | ECAP | CONTROL REGULATIONS: Reg 1, Reg 2, Reg 3 | Action | cd
A P 5

Year of Record | SCC: I, II, III, IV | Fuel, Process, Solid Waste Operating Rate | Maximum Design Rate | Sulfur Content % | Ash Content % | Heat Content 10⁶ BTU/scc | Comments | Source | Confid | Action | cd
A P 6
A P 6
A P 6
A P 6
A P 6

EPA (DUR) 330
2/73

Figure 4-1. Point source coding form.

APPENDIX C

THE GENERAL MODEL

(Excerpted from
"Evaluation of R&D
Investment Alternatives For SO_x Air
Pollution Control
Processes - Part 1)

4. THE GENERAL MODEL

4.1 The General Process Model

The plants in the models have, as far as possible, been made self-contained apart from the intake of basic raw feed materials; i.e., the plant should not be buying natural gas or electricity. If possible, it should not even be buying desulfurized fuel oil since supply cannot be assumed. There are obviously exceptions if the plant is an addition to a larger conventional plant; e.g., with stack gas scrubbing for a power plant it would be illogical not to assume a supply of power. In general, a large plant having a coal feed will generate its own power, steam and heat requirements by burning coal and scrubbing the stack gases.

It was not a primary concern to provide special chemical by-products from any process, but to avoid additional treatment facilities for impure materials by routing these side streams back to the plant fuel supply where possible. This approach simplifies the models and minimizes the effect of credits for special chemical by-products on the plant costs.

The cost of equipment and raw material, utility and waste product quantities have all been related to one or more basic process parameters; e.g., in the stack gas scrubbing models, the basic process parameters are flue gas flow rate and sulfur content of the fuel. For a plant producing high quality fuel, the basic process parameters are product flow rate and properties of the raw feed materials.

Where possible, equipment costs were related directly to the basic process parameters. However, the format of some of the estimates used to develop the models prevented this. In these cases, the available cost information was carefully examined relative to the General Cost Model to determine exactly what the costs included.

The equipment costs were extracted from these estimates by using the relationships between construction labor costs, other material costs and equipment costs given in the General Cost Model.

Each plant design was examined to fix maximum train sizes for each group of equipment. It has been assumed that N trains cost N times the cost of one train. Where a plant is largely made up of several trains, size variations were only taken in increments of their size.

For the smaller plants, it was possible to examine the cost of every item of equipment and assign an exponent of size to give cost variations. However, for the larger plants, whole sections have been grouped together. The following is given as a general guide to the exponents for equipment cost vs. size (9,14,21):

	n, $\left[\frac{\text{Cost}_2}{\text{Cost}_1} = \left(\frac{\text{Size}_2}{\text{Size}_1}\right)^n\right]$
Increasing number of trains of equipment	1.0
Blowers	0.9
Solids grinding equipment	0.8
Steam generation equipment	0.8
Process furnaces and reformers	0.7
Compressors	0.7
Power generation equipment	0.7
Solids handling equipment	0.6
Offsites	0.6
Other process units	0.6

4.2 The General Cost Model

4.2.1 Bases For Costs

All costs in the models are those in existence at the end of 1973. To update prior cost information used in the construction of the models, an annual inflation multiplication factor of 1.05 has been used. All costs other than unit costs for labor, raw materials, etc., are shown in thousands of dollars (M$).

The direct field construction labor cost, L, and the direct cost of operating labor, CO, both refer to a Gulf Coast (Houston) location. For any other location, they are adjusted through the use of a location factor, F, which is explained in section 4.3.

Whenever possible in the development of the cost models discussed in this report, major equipment costs, E, have been related to plant size variations. The reference values of E have been taken from actual plant cost estimates when these were available. Sometimes, however, the cost estimates were not available in such a detailed breakdown. In such cases, the relationships developed in the General Cost Model were used to analyze the cost data. The relationships in the General Cost Model were developed based on procedures reported and recommended in the literature (9,13) and on Kellogg's general experience.

4.2.2 Capital Cost Model

Major equipment costs, E, represent the cost of major equipment delivered to the site, but not located, tied-in to piping, instruments, etc., or commissioned. It includes material costs only. Major equipment is defined to include furnaces, heat exchangers, converters, reactors, towers, drums and tanks, pumps, compressors, transportation and conveying equipment, special equipment (filters, centrifuges, dryers, agitators, grinding equipment, cyclones, etc.), and major gas ductwork.

Other material costs, M, represent the cost of piping, electrical, process instrumentation, paint, insulation, foundations, concrete structures, and structural steel for equipment support. It does not include such items as site preparation, steel frame structures, process buildings, cafeterias, control rooms, shops, offices, etc.

M has been taken as a fixed fraction of E. Whenever possible, this fraction has been determined from an estimate covering the particular plant under consideration. This fraction is often different for each section of the plant. _If_ particular details were not available, the following relationships have been assumed (9):

Solids handling plant: $M = 0.40E$
Chemical process plant: $M = 0.80E$

Direct field construction labor costs, L, are based on Gulf Coast rates and productivities. Again, L has been taken as a fixed fraction of E. Whenever possible, it has been derived from an estimate covering the particular plant under consideration. This fraction is often different for each section of the plant. _If_ particular details were not available, the following relationships have been assumed (9):

Solids handling plant: $L = 0.40E$
Chemical process plant: $L = 0.60E$

Indirect costs associated with field labor have been assumed as follows:

Fringe benefits and payroll burden = 0.12 L
Field administration, supervision temporary facilities = 0.17 L
Construction equipment and tools = 0.14 L
Total field labor indirect costs = 0.43 L

Home office engineering includes home office construction, engineering and design, procurement, client services, accounting, cost engineering, travel and living expenses, reproduction and communication. This could range from under 10% to almost 20% of the major equipment and other material costs. In the model, this has been assumed to be 15% of the total direct material cost (E + M).

The bare cost of the plant, BARC, is defined as the sum of equipment costs, other material costs, construction labor and labor indirects, and home office engineering. For a Gulf Coast location, it is given by:

$$\begin{aligned} BARC &= E + M + L + 0.43\, L + 0.15\, (E + M) \\ &= 1.15\, (E + M) + 1.43\, L \end{aligned}$$

For any other location, it is given by:

$$BARC = 1.15\, (E + M) + 1.43\, L \cdot F$$

where F is the location factor (see section 4.3).

Taxes and insurance can be 1-4% of the bare cost. In the model, they have been assumed to be 2%. Contractor's overheads and profit could depend on several factors, but are generally in the range of 6-13% of the bare cost. A value of 10% was chosen for the model.

A contingency has been included in the model and is expressed as a fraction of the bare cost. It represents the degree of uncertainty in the process design and the cost estimate. The contingency, CONTIN, could range from zero for a well-established process to 0.20 or more for a process still under development.

The total plant investment, TPI, is defined as the sum of the bare cost (including contingency), taxes and insurance, and contractor's overheads and profit. It is therefore given by:

$$\begin{aligned}\text{TPI} &= (1.0 + \text{CONTIN})\ \text{BARC} + 0.02\ (1.0 + \text{CONTIN})\ \text{BARC} \\ &\quad + 0.10\ (1.0 + \text{CONTIN})\ \text{BARC} \\ &= 1.12\ (1.0 + \text{CONTIN})\ \text{BARC}\end{aligned}$$

In order to obtain the total capital required for construction of a particular plant, some additional costs should be added to the total plant investment. These costs are:

1. Start-up costs
2. Working capital
3. Interest during construction

Start-up costs, STC, have been assumed to be 20% of the total net annual operating cost, AOC (see section 4.2.3 for explanation of AOC). Thus:

$$\text{STC} = 0.20\ \text{AOC}$$

Working capital, WKC, is required for raw materials inventory, plant materials and supplies, etc. For simplification, it has also been assumed to be 20% of the total net annual operating cost, AOC.

Thus:

$$\text{WKC} = 0.20\ \text{AOC}$$

Interest during construction, IDC, obviously increases with the length of the construction period which, to some extent, is a function of the size of the plant. The construction of plants the size of the stack gas scrubbing units is now taking about 2-3 years and projects of the magnitude and complexity of a substitute natural gas plant or a power station are taking 4-5 years. Two different values for the interest during construction have therefore been assumed. The first is intended to be used for stack gas scrubbing units fitted to existing power plants or for constructions well under $100 million:

$$\text{IDC} = 0.12\ \text{TPI}$$

The second is for the larger, more complex plants such as substitute natural gas, solvent refined coal, and power plants:

$$\text{IDC} = 0.18\ \text{TPI}$$

The total capital required, TCR, is equal to the sum of the total plant investment, start-up costs, working capital, and interest during construction.

Thus:

$$\text{TCR} = \text{TPI} + \text{STC} + \text{WKC} + \text{IDC}$$

For stack gas scrubbing units, this can be reduced to:

$$\begin{aligned}\text{TCR} &= \text{TPI} + 0.20\ \text{AOC} + 0.20\ \text{AOC} + 0.12\ \text{TPI}\\ &= 1.12\ \text{TPI} + 0.40\ \text{AOC}\end{aligned}$$

For the larger plants, this can be reduced to:

$$\begin{aligned}\text{TCR} &= \text{TPI} + 0.20\ \text{AOC} + 0.20\ \text{AOC} + 0.18\ \text{TPI}\\ &= 1.18\ \text{TPI} + 0.40\ \text{AOC}\end{aligned}$$

From section 4.2.3, AOC is calculated from:

$$\text{AOC} = 0.078\ \text{TPI} + 2.0\ \text{TO}\cdot\text{CO}\ (1.0 + F) + \text{ANR}$$

where TO = total number of shift operators

ANR = Annual cost of raw materials, utilities, and waste disposal, less by-product credits.

Therefore, for stack gas scrubbing units, the equation for the total capital required becomes:

$$\begin{aligned} TCR &= 1.12\ TPI + 0.40\ [0.078\ TPI + 2.0\ TO \cdot CO\ (1.0 + F) + ANR] \\ &= 1.12\ TPI + 0.03\ TPI + 0.8\ TO \cdot CO\ (1.0 + F) + 0.40\ ANR \\ &= 1.15\ TPI + 0.8\ TO \cdot CO\ (1.0 + F) + 0.40\ ANR \end{aligned}$$

For the larger plants, the equation for the total capital required becomes:

$$\begin{aligned} TCR &= 1.18\ TPI + 0.40\ [0.078 TPI + 2.0\ TO \cdot CO\ (1.0 + F) + ANR] \\ &= 1.18\ TPI + 0.03\ TPI + 0.8\ TO \cdot CO\ (1.0 + F) + 0.4\ ANR \\ &= 1.21\ TPI + 0.8\ TO \cdot CO\ (1.0 + F) + 0.4\ ANR \end{aligned}$$

The buildup of costs to determine the total capital required is illustrated in Figure 4.1.

4.2.3 Operating Cost Model

The total net annual operating cost, AOC, is the total cost of operating the plant less the credits from the sale of by-products. It does not include return of capital, payment of interest on capital, income tax on equity returns or depreciation. The total net annual operating cost is made up of the following items:

1. Annual cost of raw materials, utilities, and waste disposal, less by-product credits
2. Annual cost of operating labor and supervision
3. Annual cost of maintenance labor and supervision
4. Annual cost of plant supplies and replacements
5. Annual cost of administration and overheads
6. Annual cost of local taxes and insurance

The annual cost of raw materials, utilities, and waste disposal, less by-product credits, ANR, is clearly a function of the particular process under consideration. It is given by different relationships for each model.

The total number of operators employed on all shifts, TO, is different for each process and is either given as an equation or number for each particular model. It has been assumed that each operator works 40 hours per week for 50 weeks per year (2000 hours per year). If CO is the hourly rate for an operator (Gulf Coast basis), then the annual cost of operating labor is given by:

$$\text{Operating labor (Gulf Coast)} = \frac{TO \cdot 2000 \cdot CO}{1000}$$

$$= 2\ TO \cdot CO \qquad \text{M\$/yr}$$

The annual cost of operating labor for any other location has been assumed to be:

$$\text{Operating labor} = 2\ TO \cdot CO\ (0.5 + 0.5\ F)$$

Supervision was assumed to be 15% of operating labor. Thus, the total cost of operating labor and supervision, AOL, is given by:

$$AOL = 1.15\ [2\ TO \cdot CO\ (0.5 + 0.5\ F)]$$
$$= 2.3\ TO \cdot CO\ (0.5 + 0.5\ F)$$

The annual cost of maintenance labor has been assumed to be 1.5% of the total plant investment. Maintenance supervision is 15% of maintenance labor. Therefore, the total annual cost of maintenance labor and supervision, AML, is:

$$\begin{aligned} AML &= 1.15\ (0.015\ TPI) \\ &= 0.018\ TPI\ \text{(rounded up)} \end{aligned}$$

Plant supplies and replacements include charts, cleaning supplies, miscellaneous chemicals, lubricants, paint, and replacement parts such as gaskets, seals, valves, insulation, welding materials, packing, balls (grinding), vessel lining materials, etc. The annual cost of plant supplies and replacements, APS, has been assumed to be 2% of the total plant investment. Thus:

$$APS = 0.02\ TPI$$

Administration and overheads include salaries and wages for administrators, secretaries, typists, etc., office supplies and equipment, medical and safety services, transportation and communications, lighting, janitorial services, plant protection, payroll overheads, employee benefits, etc. The annual cost of administration and overheads, AOH, has been assumed to be 70% of the annual operator, maintenance labor, and total supervision costs. Thus:

$$\begin{aligned} AOH &= 0.70\ [2.3\ TO \cdot CO\ (0.5 + 0.5F) + 0.018\ TPI] \\ &= 1.7\ TO \cdot CO\ (0.5 + 0.5F) + 0.013\ TPI\ \text{(rounded up)} \end{aligned}$$

Local taxes and insurance include property taxes, fire and liability insurance, special hazards insurance, business interruption insurance, etc. The annual local taxes and insurance, ATI, have been assumed to be 2.7% of the total plant investment. Thus:

$$ATI = 0.027\ TPI$$

The total net annual operating cost, AOC, is therefore given by:

$$\begin{aligned} AOC &= ANR + AOL + AML + APS + AOH + ATI \\ &= ANR + 2.3\ TO \cdot CO\ (0.5 + 0.5F) + 0.018\ TPI \\ &\quad + 0.02\ TPI + 1.7\ TO \cdot CO\ (0.5 + 0.5F) + 0.013\ TPI \\ &\quad + 0.027\ TPI \\ &= 0.078\ TPI + 4.0\ TO \cdot CO\ (0.5 + 0.5F) + ANR \\ &= 0.078\ TPI + 2.0\ TO \cdot CO\ (1.0 + F) + ANR \end{aligned}$$

In order to obtain the total annual production cost, the following items must be added to the total net annual operating cost:

1. depreciation
2. average yearly interest on borrowed capital
3. average yearly net return on equity
4. average yearly income tax

The straight-line method was used to determine depreciation, based on the total capital required less the working capital. For stack gas scrubbing units (15 year life), the annual depreciation, ACR, is:

$$\begin{aligned} ACR &= 1/15\ (TCR-WKC) \\ &= 0.067\ (TCR-0.20\ AOC) \end{aligned}$$

For substitute natural gas and solvent refined coal plants (20 year life), it is given by:

$$ACR = 0.050\ (TCR - 0.20\ AOC)$$

For power plants, both conventional and combined cycle (28 year life), it is:

$$ACR = 0.036\ (TCR - 0.20\ AOC)$$

Interest on debt and return on equity are calculated following a procedure recommended in the literature (13) and illustrated in Appendix A. The procedure assumes a fixed debt-to-equity ratio, an interest rate on debt, and the required net (after tax) rate of return on equity. Interest on debt and return on equity are calculated over the plant life, and the yearly average is expressed as a percentage of the total capital required (TCR). Assuming a 75%/25% debt-to-equity ratio, a 9% per year interest rate, and a 15% per year net rate of return on equity, the annual interest and return, AIC, is given by:

$$AIC = 0.054\ TCR$$

Federal income tax is the average yearly income tax over the plant life, expressed as a percentage of the total capital required. The calculation of income tax is illustrated in Appendix A. Based on the assumptions listed in the preceding paragraph and an assumed tax rate of 48%, the annual federal income tax, AFT, is given by :

$$AFT = 0.018\ TCR$$

The total annual production cost, TAC, is given by:

$$TAC = AOC + ACR + AIC + AFT$$

For stack gas scrubbing plants, this can be reduced as follows:

$$\begin{aligned} TAC &= AOC + 0.067\ (TCR - 0.20\ AOC) + 0.054\ TCR + 0.018\ TCR \\ &= AOC + 0.067\ TCR - .013\ AOC + 0.054\ TCR + 0.018\ TCR \\ &= 0.139\ TCR + 0.99\ AOC \end{aligned}$$

Substituting for TCR and AOC from preceeding equations:

$$\begin{aligned} TAC &= 0.139\ [1.15\ TPI + 0.8\ TO \cdot CO\ (1.0 + F) + 0.40\ ANR] \\ &\quad + 0.99\ [0.078\ TPI + 2.0\ TO \cdot CO\ (1.0 + F) + ANR] \\ &= 0.237\ TPI + 2.1\ TO \cdot CO\ (1.0 + F) + 1.04\ ANR \end{aligned}$$

Making the appropriate substitutions, the total annual production cost for substitute natural gas and solvent refined coal plants is:

$$TAC = 0.225\ TPI + 2.1\ TO \cdot CO\ (1.0 + F) + 1.04\ ANR$$

For power plants, this equation becomes:

$$TAC = 0.208\ TPI + 2.1\ TO \cdot CO\ (1.0 + F) + 1.04\ ANR$$

The buildup of costs to determine the total annual production cost is illustrated in Figure 4.2.

4.3 Effect of Location on Plant Cost

The cost models have been developed using U.S. Gulf Coast 1973 costs as a basis. In order to predict plant costs for other locations, factors have been developed which relate construction labor costs at various locations to Gulf Coast labor costs. By multiplying the field labor construction portion of plant cost by this location factor, the total plant cost is adjusted to the desired location.

Labor rates for different crafts were obtained from the literature (10) and escalated to the end of 1973. Using an average craft mix obtained from in-house information (12), an average construction labor rate was obtained for each location. Productivity factors for the various locations, also obtained from in-house data, were used to create the rate for equal work output. These rates were then normalized, using Houston (Gulf Coast) as a basis, to yield relative field labor construction costs.

Table 4.1 lists the relative labor costs determined for twenty cities. They range from 1.0 for Houston to 2.08 for New York. Costs are generally highest in the Northeastern quarter of the country and lowest in the South. These factors are shown on a map of the U.S. in Figure 4.3.

Table 4.2 lists average location factors for each state. Allowance has been made in the factor for the importation of temporary labor to the more remote states. The factors are shown on a map of the U.S. in Figure 4.4.

Figure 4.5 gives the relationship between major equipment cost, E, total plant investment, TPI, and location factor, F, when the contingency, CONTIN, is zero.

TABLE 4.1

LOCATION FACTORS FOR MAJOR U.S. CITIES

Location	Location Factor F
Atlanta	1.10
Baltimore	1.41
Birmingham	1.16
Boston	1.23
Chicago	1.52
Cincinnati	1.53
Cleveland	1.86
Dallas	1.07
Denver	1.03
Detroit	1.73
Kansas City	1.37
Los Angeles	1.44
Minneapolis	1.54
New Orleans	1.16
New York	2.08
Philadelphia	1.82
Pittsburgh	1.52
St. Louis	2.01
San Francisco	1.45
Seattle	1.21
Houston	1.00

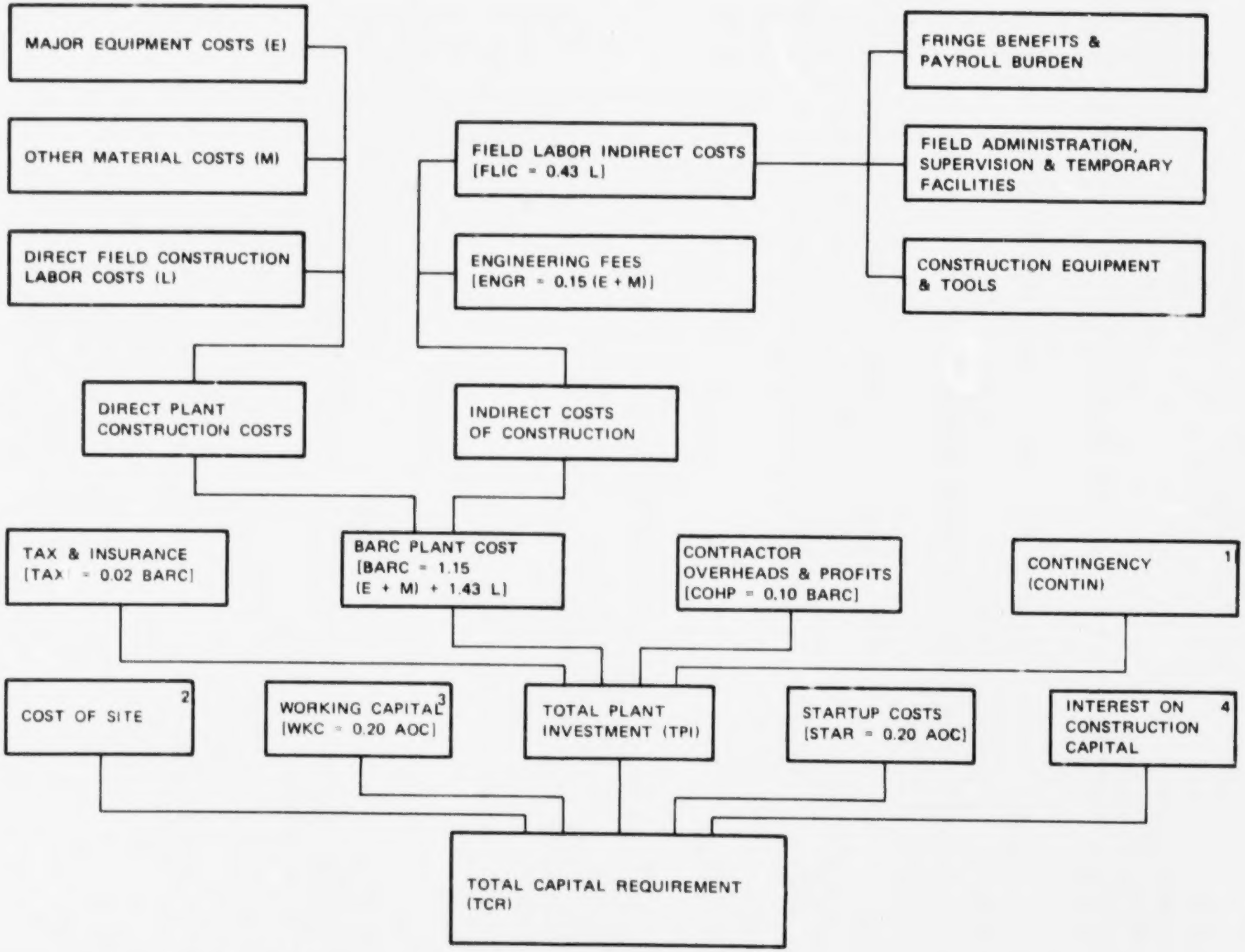
TABLE 4.2

AVERAGE LOCATION FACTORS FOR EACH STATE

State	Location Factor
Alabama	1.2
Alaska	2.1
Arizona	1.3
Arkansas	1.2
California	1.5
Colorado	1.2
Connecticut	1.7
Delaware	1.4
D.C.	1.4
Florida	1.2
Georgia	1.1
Hawaii	2.0
Idaho	1.3
Illinois	1.7
Indiana	1.6
Iowa	1.5
Kansas	1.4
Kentucky	1.5
Louisiana	1.1
Maine	1.2
Maryland	1.4
Massachusetts	1.3
Michigan	1.7
Minnesota	1.5
Mississippi	1.1
Missouri	1.6
Montana	1.3
Nebraska	1.4
Nevada	1.4
New Hampshire	1.2
New Jersey	2.1
New Mexico	1.3
New York	2.1
N. Carolina	1.2
North Dakota	1.3
Ohio	1.6
Oklahoma	1.4
Oregon	1.2
Pennsylvania	1.6
Rhode Island	1.3
S. Carolina	1.1
South Dakota	1.3
Tennessee	1.2
Texas	1.1
Utah	1.2
Vermont	1.2
Virginia	1.4
Washington	1.2
W. Virginia	1.5
Wisconsin	1.5
Wyoming	1.3

FIGURE 4.1

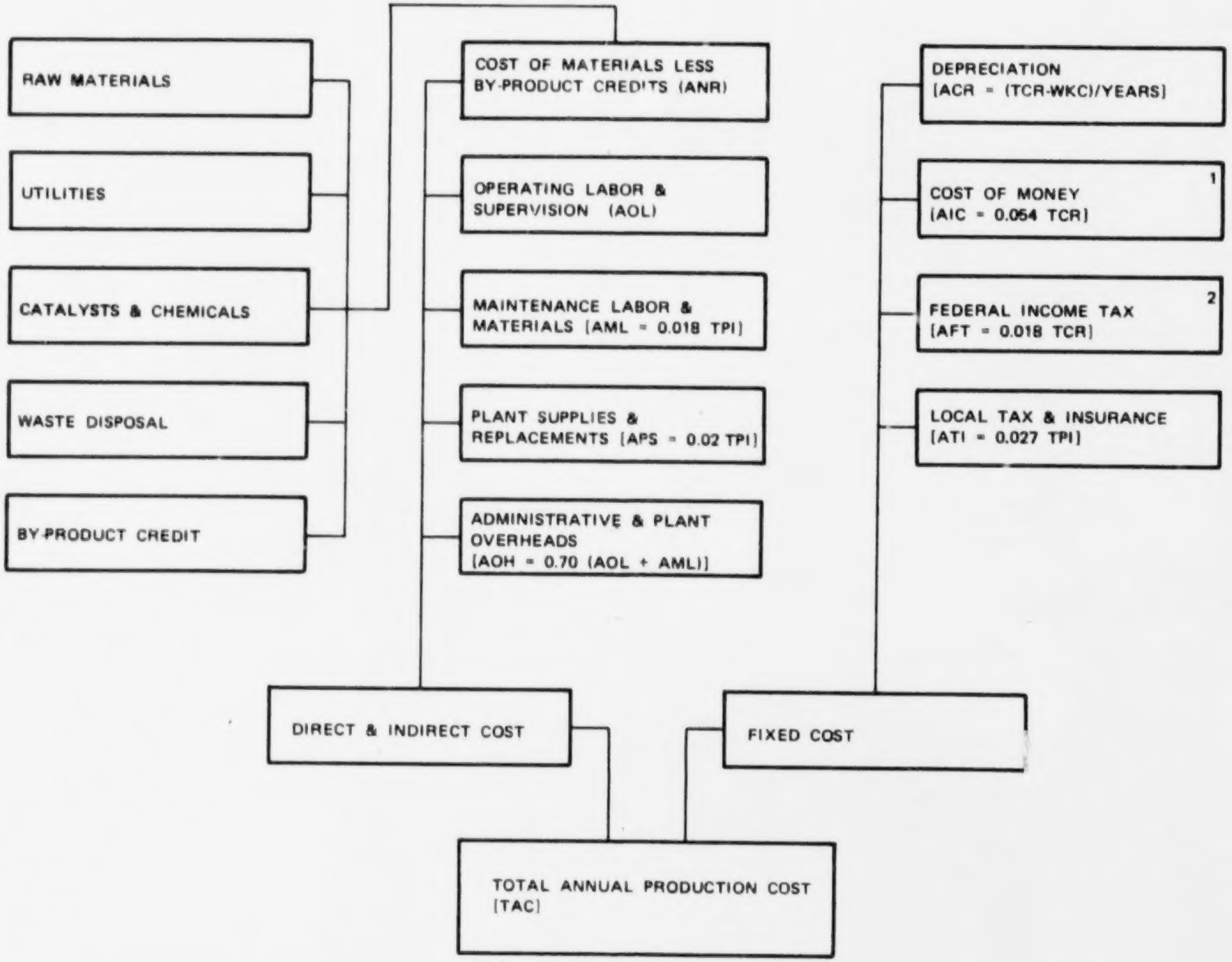
RELATIONSHIP BETWEEN CAPITAL COST FACTORS IN THE GENERAL COST MODEL


MAJOR EQUIPMENT COSTS (E)
OTHER MATERIAL COSTS (M)
DIRECT FIELD CONSTRUCTION LABOR COSTS (L)
FIELD LABOR INDIRECT COSTS [FLIC = 0.43 L]
ENGINEERING FEES [ENGR = 0.15 (E + M)]
FRINGE BENEFITS & PAYROLL BURDEN
FIELD ADMINISTRATION, SUPERVISION & TEMPORARY FACILITIES
CONSTRUCTION EQUIPMENT & TOOLS
DIRECT PLANT CONSTRUCTION COSTS
INDIRECT COSTS OF CONSTRUCTION
TAX & INSURANCE [TAX = 0.02 BARC]
BARC PLANT COST [BARC = 1.15 (E + M) + 1.43 L]
CONTRACTOR OVERHEADS & PROFITS [COHP = 0.10 BARC]
CONTINGENCY (CONTIN) 1
COST OF SITE 2
WORKING CAPITAL 3 [WKC = 0.20 AOC]
TOTAL PLANT INVESTMENT (TPI)
STARTUP COSTS [STAR = 0.20 AOC]
INTEREST ON CONSTRUCTION CAPITAL 4
TOTAL CAPITAL REQUIREMENT (TCR)

1. SEE DEFINITION ON PAGE 58.
2. COST WOULD NORMALLY BE INCLUDED ONLY IF PURCHASE IS REQUIRED. COST IS USUALLY SMALL AND HAS NOT BEEN INCLUDED IN MODEL.
3. SEE NOTE 3 OF FIGURE 4.2.
4. SEE FIGURE 4.2.

FIGURE 4.2

RELATIONSHIP BETWEEN PRODUCTION COST FACTORS IN THE GENERAL COST MODEL


RAW MATERIALS
UTILITIES
CATALYSTS & CHEMICALS
WASTE DISPOSAL
BY-PRODUCT CREDIT
COST OF MATERIALS LESS BY-PRODUCT CREDITS (ANR)
OPERATING LABOR & SUPERVISION (AOL)
MAINTENANCE LABOR & MATERIALS [AML = 0.018 TPI]
PLANT SUPPLIES & REPLACEMENTS [APS = 0.02 TPI]
ADMINISTRATIVE & PLANT OVERHEADS [AOH = 0.70 (AOL + AML)]
DEPRECIATION [ACR = (TCR-WKC)/YEARS]
COST OF MONEY [AIC = 0.054 TCR] 1
FEDERAL INCOME TAX [AFT = 0.018 TCR] 2
LOCAL TAX & INSURANCE [ATI = 0.027 TPI]
DIRECT & INDIRECT COST
FIXED COST
TOTAL ANNUAL PRODUCTION COST [TAC]

1. AVERAGE OVER THE PLANT LIFE, ASSUMING 75% DEBT AT 9% INTEREST RATE PER YEAR, AND 25% EQUITY GIVING A NET RETURN OF 15%.
2. AVERAGE OVER THE PLANT LIFE, ASSUMING 48% FEDERAL INCOME TAX RATE.
3. ANNUAL OPERATING COST IS: AOC = ANR + AOL + AML + APS + AOH + ATI.

FIGURE 4.3

LOCATION FACTORS FOR SELECTED CITIES

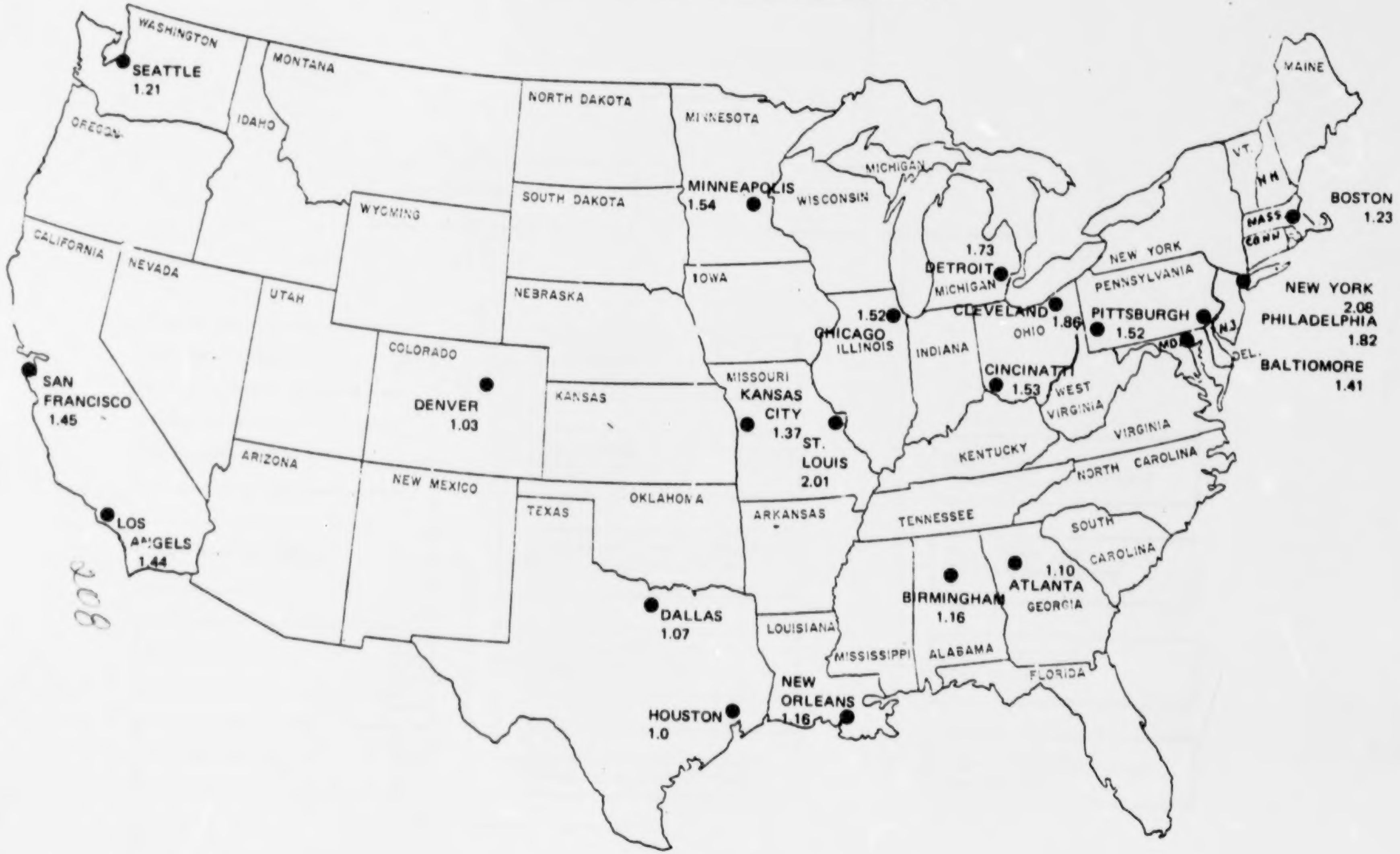

WASHINGTON
SEATTLE
1.21
OREGON
IDAHO
MONTANA
NORTH DAKOTA
MINNESOTA
MINNEAPOLIS
1.54
SOUTH DAKOTA
WYOMING
WISCONSIN
MICHIGAN
CALIFORNIA
NEVADA
UTAH
NEBRASKA
IOWA
1.73
DETROIT
MICHIGAN
1.52
CHICAGO
ILLINOIS
INDIANA
CLEVELAND
1.86
OHIO
NEW YORK
PENNSYLVANIA
PITTSBURGH
1.52
VT.
NH
MASS
CONN
MAINE
BOSTON
1.23
NEW YORK
2.08
NJ
PHILADELPHIA
1.82
MD
DEL.
BALTIMORE
1.41
SAN FRANCISCO
1.45
COLORADO
DENVER
1.03
KANSAS
MISSOURI
KANSAS CITY
1.37
ST. LOUIS
2.01
CINCINATTI
1.53
WEST VIRGINIA
VIRGINIA
KENTUCKY
NORTH CAROLINA
ARIZONA
NEW MEXICO
TEXAS
OKLAHOMA
ARKANSAS
TENNESSEE
SOUTH CAROLINA
LOS ANGELS
1.44
DALLAS
1.07
BIRMINGHAM
1.16
ATLANTA
1.10
GEORGIA
LOUISIANA
MISSISSIPPI
ALABAMA
FLORIDA
NEW ORLEANS
1.16
HOUSTON
1.0

FIGURE 4.4

AVERAGE LOCATION FACTORS BY STATE

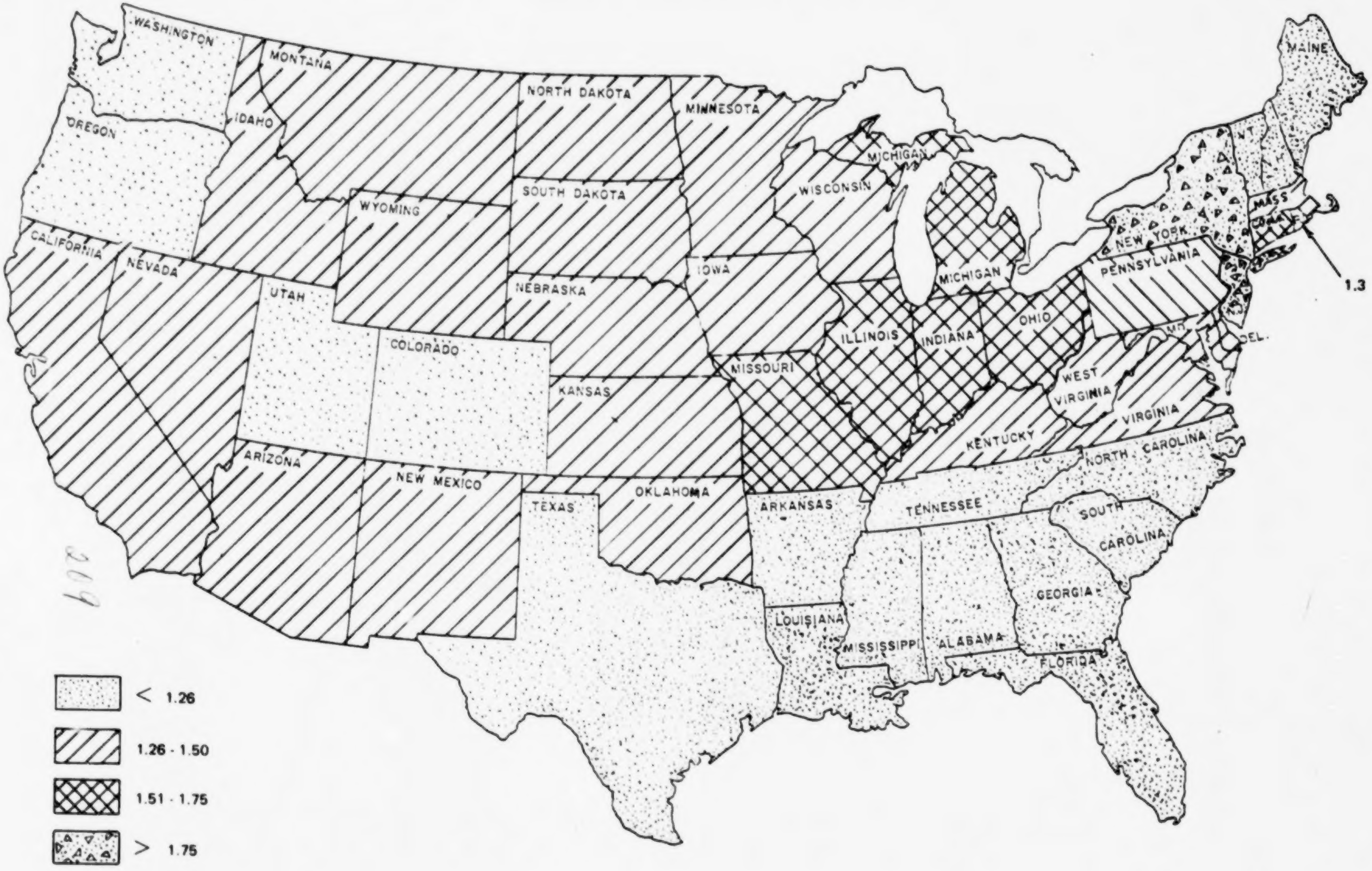
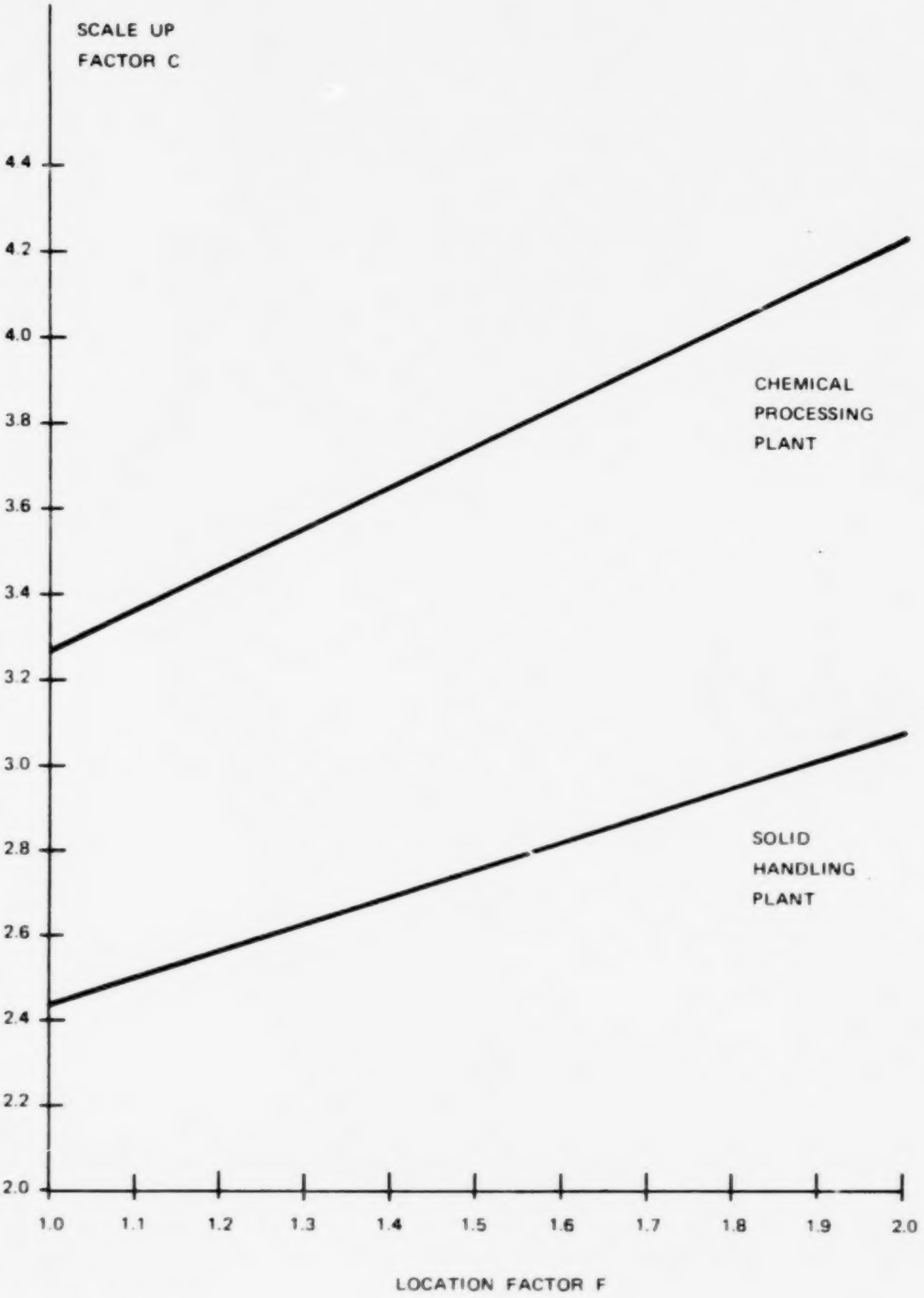

WASHINGTON
OREGON
CALIFORNIA
NEVADA
IDAHO
MONTANA
WYOMING
UTAH
COLORADO
ARIZONA
NEW MEXICO
NORTH DAKOTA
SOUTH DAKOTA
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA
IOWA
MISSOURI
ARKANSAS
LOUISIANA
WISCONSIN
MICHIGAN
MICHIGAN
ILLINOIS
INDIANA
OHIO
KENTUCKY
TENNESSEE
MISSISSIPPI
ALABAMA
GEORGIA
FLORIDA
SOUTH CAROLINA
NORTH CAROLINA
VIRGINIA
WEST VIRGINIA
PENNSYLVANIA
NEW YORK
MD.
DEL.
MASS
CONN.
VT.
N.H.
MAINE
1.3
< 1.26
1.26 - 1.50
1.51 - 1.75
> 1.75

FIGURE 4.5

EFFECT OF LOCATION FACTOR ON TOTAL PLANT INVESTMENT (CONTINGENCY = 0)

$$TPI = C \cdot E$$



APPENDIX D

DERIVATION OF EQUATION FOR TOTAL ANNUAL PRODUCTION COST DISCOUNTED CASH FLOW METHOD

Using the discounted cash flow method, a constant annual production cost is calculated which gives the desired discounted rate of return over the project life. This production cost includes net operating expenses, capital recovery, and return on investment. The actual cash flow would be greater during the early years of a project, gradually diminishing over the life of the plant. This provides the desired return on investment while maintaining the production cost constant.

In any year, the cash flow, CF, is given by the following expression:

CF = depreciation (DEP)
+ net income after taxes (INC)
- capital investment (TCR)

Using a tax rate of 48%, the net income after taxes is 52% of the taxable income, TINC. Taxable income is given by:

TINC = total production cost (TAC), which includes return on investment
- net operating expenses (AOC)
- depreciation (DEP)

Therefore, the net income after taxes is:

$$\mathrm{INC} = 0.52\ (\mathrm{TAC} - \mathrm{AOC} - \mathrm{DEP})$$

and the expression for cash flow becomes:

$$\mathrm{CF} = \mathrm{DEP} + 0.52\ (\mathrm{TAC} - \mathrm{AOC} - \mathrm{DEP}) - \mathrm{TCR}$$

By applying a discount factor, DF, to the cash flow, the discounted cash flow, DCF, is obtained. The discount factor is:

$$DF = \left(\frac{1}{1+r}\right)^n$$

where r = rate of return, expressed as a fraction
n = year in which discount is being applied.

Thus, the discounted cash flow can be determined by the following equation:

$$DCF = \left(\frac{1}{1+r}\right)^n [DEP + 0.52 (TAC - AOC - DEP) - TCR]$$

The discounted cash flow is determined for each year in terms of known quantities and the only unknown, the total production cost (TAC). Setting the sum of all discounted cash flows over the life of the plant equal to zero provides the equation for calculating the total production cost.

Year 0

The total capital requirement, TCR, is treated as a capital cost at start-up completion. Start-up costs, STC, are treated as an expense at start-up completion.

$$DCF_0 = \left(\frac{1}{1+r}\right)^0 (-TCR-STC) = -TCR-STC$$

Year n

An accelerated depreciation schedule (sum-of-the-years-digits method) has been used. Depreciation is taken over the plant life, based on the total plant investment, TPI. The depreciation is taken over the plant life, based on the total plant investment, TPI. The depreciation in year n is given by:

$$DEP_n = \frac{2(\ell-n+\ell)}{\ell(\ell+1)} \quad TPI$$

where ℓ = plant life, years

Substituting this into the general expression for discounted cash flow gives, for year n:

$$DCF_n = \left(\frac{1}{1+r}\right)^n \left[0.48 \times \frac{2(\ell-n+1)}{\ell(\ell+1)} \quad TPI + 0.52 \; (TAC - \right.$$

$$\left. - AOC)\right]$$

At the end of the plant life, the working capital, WKC, is recovered. The discounted cash flow resulting from recovery of this capital is:

$$DCF = \left(\frac{1}{1+r}\right)^{\ell} \; (WKC)$$

The total discounted cash flow for years 1 through ℓ is:

$$DCF_{1\rightarrow\ell} = \left(\frac{1}{1+r}\right)^{\ell} (WKC) + \sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^{n} \left[0.48 \times \frac{2(\ell-n+1)}{\ell(\ell+1)} \quad TPI + \right.$$

$$\left. + 0.52 \; (TAC-AOC)\right]$$

TAC

The total discounted cash flow over the life of the plant is given by:

$$DCF = \left(\frac{1}{1+r}\right)^{\ell} \; (WKC) + \sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^{n} \left[0.48 \times \frac{2(\ell-n+1)}{\ell(\ell+1)} \; TPI + 0.52 \right.$$

$$\left. (TAC-AOC)\right] - TCR - STC$$

Setting DCF equal to zero and rearranging terms, the expression becomes:

$$\sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n \left[0.48 \times \frac{2(\ell-n+1)}{\ell(\ell+1)} \quad \text{TPI} + 0.52 \ (\text{TAC}-\text{AOC})\right] = \text{TCR} + \text{STC} - \frac{\text{WKC}}{(1+r)^{\ell}}$$

Solving for TAC,

$$\sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n \left[0.48 \times \frac{2(\ell-n+1)}{\ell(\ell+1)}\right] \text{TPI} + \sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n (0.52) \ (\text{TAC}-\text{AOC}) =$$

$$\text{TCR} + \text{STC} + \frac{\text{WKC}}{(1+r)^{\ell}}$$

$$0.48 \ \text{TPI} \times \frac{2}{\ell(\ell+1)} \sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n (\ell-n+1) + 0.52 \ (\text{TAC}-\text{AOC}) \sum_{n=1}^{1} \left(\frac{1}{1+r}\right) =$$

$$\text{TCR} + \text{STC} + \frac{\text{WKC}}{(1+r)^{\ell}}$$

$$0.52(\text{TAC}-\text{AOC}) \sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n = \text{TCR} + \text{STC} + \frac{\text{WKC}}{(1+r)^{\ell}} - 0.48 \ \text{TPI} \times$$

$$\frac{2}{\ell(\ell+1)} \sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n (\ell-n+1)$$

$$\text{TAC} = \frac{\text{TCR}+\text{STC}+ \dfrac{\text{WKC}}{(1+r)^{\ell}} - 0.48 \ \text{TPI} \times \dfrac{2}{\ell(\ell+1)} \displaystyle\sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n (\ell-n-1)}{0.52 \displaystyle\sum_{n=1}^{1} \left(\frac{1}{1+r}\right)^n} + \text{AOC}$$

The summation term in the denominator is the reciprocal of the uniform annual series capital recovery factor, which is given by:

$$\text{capital recovery factor} = \frac{r(1+r)^{\ell}}{(1+r)^{\ell} - 1}$$

Thus,

$$TAC = \frac{1}{0.52} \left[\frac{r(1+r)^{\ell}}{(1+r)^{\ell}-1}\right] \left[TCR+STC- \frac{WKC}{(1+r)^{\ell}} - 0.48\ TPI \times \frac{2}{\ell(\ell+1)} \frac{\ell+1-n}{(1+r)^{n}}\right] + AOC$$

A 10 percent rate of return has been assumed for all discounted cash flow calculations. Stack gas scrubbing units have been assumed to have a useful life of 15 years. Using these values, the equation for TAC can be simplified to:

$$TAC = \frac{1}{0.52} \left[\frac{0.10\ (1.10)^{15}}{(1.10)^{15} -1}\right]\left[TCR + STC - \frac{WKC}{(1.10)^{15}} - 0.48\ TPI \times \frac{2}{(15)(16)} \frac{16-n}{(1.10)^{n}}\right] + AOC =$$

$$\frac{TCR+STC-0.239\ WKC - 0.291\ TPI}{3.955} + AOC$$

For stack gas scrubbing units, the following substitutions can be made:

$TCR = TPI + WKC + IDC$

$WKC = 0.20\ (AOC + ACRED)$

$IDC = 0.135\ TPI$

$STC = 0.20\ (AOC + ACRED)$

$AOC = 0.078\ TPI + 2.0\ TO \cdot CO\ (1.0 + F) + ANR$

where IDC = return on investment during construction

ACRED = annual credit for the sale of any by-products

TO = total number of shift operators required
CO = hourly wage of operator, Gulf Coast basis
F = location factor (used to convert labor costs from a Gulf Coast basis to any other location)
ANR = annual cost of raw materials and utilities, less by-product credits.

Making these substitutions,

$$
\begin{aligned}
\mathrm{TAC} &= \frac{\mathrm{TPI} + \mathrm{WKC} + \mathrm{IDC} + \mathrm{STC} - 0.239\ \mathrm{WKC} - 0.291\ \mathrm{TPI}}{3.955} + \mathrm{AOC} \\
&= 0.1793\ \mathrm{TPI} + 0.1924\ \mathrm{WKC} + 0.2528\ \mathrm{IDC} + 0.2528\ \mathrm{STC} + \mathrm{AOC} \\
&= 0.1793\ \mathrm{TPI} + 0.1924(0.20)(\mathrm{AOC}+\mathrm{ACRED}) + 0.2528(0.135\ \mathrm{TPI}) \\
&\quad + 0.2528(0.20)(\mathrm{AOC}+\mathrm{ACRED}) + \mathrm{AOC} \\
&= 0.213\ \mathrm{TPI} + 1.09\ \mathrm{AOC} + 0.09\ \mathrm{ACRED} \\
&= 0.213\ \mathrm{TPI} + 1.09[0.078\ \mathrm{TPI} + 2.0\ \mathrm{TO}\cdot\mathrm{CO}(1.0+\mathrm{F}) + \mathrm{ANR}] \\
&\quad + 0.09\ \mathrm{ACRED}
\end{aligned}
$$

$$\mathrm{TAC} = 0.298\ \mathrm{TPI} + 2.18\ \mathrm{TO}\cdot\mathrm{CO}(1.0+\mathrm{F}) + 1.09\ \mathrm{ANR} + 0.09\ \mathrm{ACRED}$$

APPENDIX E

STACK GAS SCRUBBING COST MODELS FOR UTILITY PLANTS

SUMMARY

COST MODEL FOR THE WET LIMESTONE PROCESS*

Capital Cost Model

In order to estimate capital costs, the wet limestone process was divided into three sections:

1) Chemical processing equipment
2) Solids handling equipment
3) Settling pond

Based on the Catalytic estimate (3), costs were determined for the pond and all pieces of equipment. These costs were then related to primary utility plant variables in order to allow scaling of costs to different size plants.

The following equations summarize the chemical processing equipment costs, EC, and the solids handling equipment costs, ES:

$$EC = \sum_{n=1}^{NA} RB[1041(GT/550)^{0.5} + 408(GT/550)^{0.9}]_n + 238\ RP\ (GP/3300)^{0.5} + 201(SF/28)^{0.5} \qquad M\ \$$$

$$ES = 1680\ (SF/28)^{0.9} \qquad M\ \$$$

where GP = total gas flow rate into the control unit (MACFM)
GT = gas flow rate to each scrubber train (MACFM)
NA = number of scrubber trains
SF = total sulfur flow rate into the control unit (M lbs/hr of sulfur)

RB and RP are retrofit factors which are included to reflect the difficulty and increased cost of retrofitting a control system in an existing plant, as opposed to a new installation. The cost of the settling pond, P, was found to be:

---

*For complete description, see section 5. of Part 1 of this study.

$$P = 5000 \left(\frac{SF \cdot LF}{28}\right)^{0.9} \qquad \text{M \$}$$

where LF = plant load factor (expressed as a fraction)

Other material costs, M, and field labor costs, L, were derived from the Catalytic estimate and expressed as a fraction of equipment costs. They are summarized as follows:

$$M = 0.82\ EC + 0.09\ ES \qquad \text{M \$}$$
$$L = 0.39\ EC + 0.18\ ES \qquad \text{M \$}$$

The bare cost of the plant, BARC, the total plant investment, TPI, and the total capital requirement, TCR, are given by the appropriate equations in the General Cost Model. Note that since the major portion of the cost of the settling pond is the labor cost for excavation and construction, this item has been included with the overall field labor cost. Thus:

$$BARC = 1.15\ (E+M) + (P + 1.43\ L)\ F \qquad \text{M \$}$$
$$TPI = 1.12\ (1.0 + CONTIN)\ BARC \qquad \text{M \$}$$
$$TCR = 1.15\ TPI + 0.8\ TO \cdot CO(1+F) + 0.4\ ANR \qquad \text{M \$}$$

where F = location factor (used to convert labor costs from a Gulf Coast basis to any other location)

CONTIN = contingency for the process design and cost estimate (expressed as a fraction)

TO = total number of shift operators required

CO = hourly wage of operator, Gulf Coast basis (\$/hr.)

ANR = cost of raw materials and utilities (M\$/yr.)

Operating Cost Model

Raw materials and utilities consumed by the process include limestone, ammonia, water, fuel oil, and electricity. Process requirements were derived from the Catalytic estimate and related to the primary utility plant variables. The cost of raw materials and utilities, ANR, was determined to be:

$$\begin{aligned} \mathrm{ANR} = {} & 600\ \mathrm{CL}\cdot\mathrm{LF}\ (\mathrm{SF}/28) + 0.43\ \mathrm{CA}\ (\mathrm{SF}/28) \\ & + 230\ \mathrm{CW}\cdot\mathrm{LF}\ [(\mathrm{GP}/3300) + (\mathrm{SF}/28)] \\ & + 1800\ \mathrm{CF}\cdot\mathrm{LF}\ (\mathrm{GP}/3300) \\ & + \mathrm{CE}\cdot\mathrm{LF}\ [213\ (\mathrm{GP}/3300) + 35\ (\mathrm{SF}/28)] \qquad \mathrm{M\ \$/yr.} \end{aligned}$$

Unit costs used in the model are:

limestone - CL = \$4.00/ton
ammonia - CA = \$50.00/ton
water - CW = \$0.20/10^3gal.
fuel oil CF = \$0.80/10^6Btu
electricity - CE = 88.00 mills/KWH

The total net annual operating cost, AOC, and the total annual production cost, TAC, are obtained from the General Cost Model:

$$\mathrm{AOC} = 0.078\ \mathrm{TPI} + 2.0\ \mathrm{TO}\cdot\mathrm{CO}\ (1.0+\mathrm{F}) + \mathrm{ANR} \qquad \mathrm{M\ \$/yr.}$$

$$\mathrm{TAC} = 0.237\ \mathrm{TPI} + 2.1\ \mathrm{TO}\cdot\mathrm{CO}\ (1.0+\mathrm{F}) + 1.04\ \mathrm{ANR} \qquad \mathrm{M\ \$/yr.}$$

The total number of shift operators, TO, for the wet limestone process was determined to be eight (two men/shift) for plant capacities of 200 MW or more. For plants smaller than 200 MW, the cost of operating labor has been assumed to decrease linearly with size.

COST MODEL FOR THE WELLMAN/ALLIED PROCESS*

Capital Cost Model

The Wellman/Allied process was divided into four sections:

1) Absorber area
2) SO_2 regeneration area
3) Purge/make-up area
4) SO_2 reduction area (Allied Chemical plant)

Based on the Wellman-Lord and Allied Chemical estimate, costs were determined for all pieces of equipment and related to utility plant variables for scaling purposes. The following equations summarize the equipment costs for the absorber area, EA, for the SO_2 regeneration area, ES, for the purge/make-up area, EP, and for the SO_2 reduction area, ER:

$$\begin{aligned} EA = & \sum_{n=1}^{NA} RB[726(GT/550)^{0.5} + 639(GT/550)^{0.9}]_n \\ & + 119 \cdot RP(GP/3300)^{0.5} \\ & + [133(S7/7)^{0.5} + 127\ IF(S7/7)^{0.6}]\ N7 \qquad \text{M \$} \end{aligned}$$

$$ES = [209(S7/7)^{0.5} + 618(S7/7)^{0.6} + 157(S7/7)^{0.9}]\ N7 \qquad \text{M \$}$$

$$\begin{aligned} EP = & [525(S28/28)^{0.5} + 380(S28/28)^{0.6} + 86(S28/28)^{0.7} \\ & + 306(S28/28)^{0.8} + 519(S28/28)^{0.9}]\ N28 \qquad \text{M \$} \end{aligned}$$

$$ER = 998(SF/28)^{0.5} + 287(SF/28)^{0.6} + 683(SF/28)^{0.9} \qquad \text{M \$}$$

where S7 = sulfur flow rate per train where the maximum flow per train is limited to 7000 lbs/hr. of sulfur (M lbs/hr of sulfur)

---

* For complete description, see section 6. of Part I of this study.

S28 = sulfur flow rate per train where the maximum flow per train is limited to 28,000 lbs./hr. of sulfur (M lbs./hr. of sulfur)

N7 = number of trains of size S7

N28 = number of trains of size S28

IF = particulate index; = 1 if particulates present, = 0 if particulates absent.

Other material costs, M, and field labor costs, L, were derived from the estimate and are summarized as follows:

$$M = 0.429\ EA + 0.742\ ES + 0.827\ EP + 0.772\ ER \qquad M\ \$$$

$$L = 0.224\ EA + 0.310\ ES + 0.433\ EP + 0.623\ ER \qquad M\ \$$$

The bare cost, BARC, the total plant investment, TPI, and the total capital requirement, TCR, are given by equations in the General Cost Model:

$$BARC = 1.15\ (E+M) + 1.43\ L\cdot F \qquad M\ \$$$

$$TPI = 1.12\ (1.0 + CONTIN)\ BARC \qquad M\ \$$$

$$TCR = 1.15\ TPI + 0.8\ TO\cdot CO\ (1+F) + 0.4\ ANR \qquad M\ \$$$

Operating Cost Model

Raw materials and utilities consumption of the Wellman/Allied process include sodium carbonate, natural gas, filter aid, power (electricity), steam, cooling water, process water, and fuel oil. Possible credits include sulfur, and a purge solids stream. Process requirements for raw materials and utilities, and production of by-products were derived from the Wellman-Lord and Allied Chemical estimate and related to the utility plant variables. The cost of raw materials and utilities less credits, ANR, was found to be:

$$\begin{aligned}\mathrm{ANR} = {} & 28.2\ \mathrm{CS \cdot LF(SF/28)} + 1460\ \mathrm{CN \cdot LF(SF/28)} \\ & + 1.24\ \mathrm{CFA \cdot LF \cdot IF(GP/3300)} \\ & + \mathrm{CE \cdot LF}\ [154\mathrm{(GP/3300)} + 79\mathrm{(SF/28)}] \\ & + 5430\ \mathrm{CH \cdot LF(SF/28)} \\ & + \mathrm{CCW \cdot LF}[856\mathrm{(GP/3300)} + 19{,}900\mathrm{(SF/28)}] \\ & + 64\mathrm{(SF/28)}\ \mathrm{CW \cdot LF} + 1800\ \mathrm{CF \cdot LF(GP/3300)} \\ & - 95.4\mathrm{(SF/28)VSC \cdot LF} - 37.3\mathrm{(SF/28)}\ \mathrm{VPS \cdot LF} \qquad \mathrm{M\ \$/yr.}\end{aligned}$$

Unit costs used in the model are:

sodium carbonate	- CS	= \$40.00/ton
natural gas	- CN	= \$0.50/10^3SCF
filter aid	- CFA	= \$50.00/ton
electricity	- CE	= 8.00 mills/KWH
steam	- CH	= \$0.50/10^3lbs.
cooling water	- CCW	= \$0.02/10^3gal.
process water	- CW	= \$0.20/10^3gal.
fuel oil	- CF	= \$0.80/MMBtu
sulfur	- VSC	= \$5.00/long ton
purge solids	- VPS	= -\$1.00/ton

The total net annual operating cost, AOC, and the total annual production cost, TAC, are obtained from the General Cost Model:

$$\mathrm{AOC} = 0.078 + \mathrm{PI} + 2.0\ \mathrm{TO \cdot CO(1.0{+}F)} + \mathrm{ANR} \qquad \mathrm{M\ \$/yr.}$$

$$\mathrm{TAC} = 0.237\ \mathrm{TPI} + 2.1\ \mathrm{TO \cdot CO}\ \mathrm{(1.0{+}F)} + 1.04\ \mathrm{ANR} \qquad \mathrm{M\ \$/yr.}$$

The total number of shift operators, TO, for the Wellman/Allied process was found to be sixteen (four men/shift) for plant capacities of 200 MW or more. For plants smaller than 200 MW, the cost of operating labor has been assumed to decrease linearly with size.

APPENDIX F

PACKAGED LIMESTONE SCRUBBING SYSTEM FOR 50 MMBTU/HR BOILER

Description of Mechanical Equipment

A. Scrubbing System

100-E Venturi Scrubber: Variable throat for constant ΔP
18,000 ACFM @ 300°F (12,300 SCFM)
198 GPM @ 127°F of 19 wt % limestone slurry
Inlet dust loading = 4.74 gr/MSCFM
Outlet dust loading = .021 gr/MSCFM
L/G = 11.0 GPM/MSCFM inlet gas
$\Delta P = 10'' \, H_2O$
C. S. with platsite 7122 (a plastic coating) and 2 in Kaocrete
Dimensions: 2'4" w x 4'6" l x 5' h (UOP)

100-F Venturi Recirculation Tank 5 minutes retention
1192 gal. of 19 % limestone slurry
3/16" C. S., rubber lined, open top
1/4" flat bottom
Dimensions: 6' dia. x 6' h (Smith Industries)

103-L Venturi Recirculating Tank Agitator
For 100-F to maintain solids suspension
Open-type agitator with worm-gear reducer drive mechanism
Speed = 1100 ft/min HP = 5.0
Dimensions: 6'3" dia. x 7'8" h (Denver)

100-J Venturi Recirculating Pump and Drive
2 at 100% capacity (1 spare)
224 GPM of 19 wt % limestone slurry @ 127°F
Centrifugal, outside, slide type maintenance base,

rubber internals
HP = 15 ea
Size 3" suction, 3" discharge
Dimensions: 3' w x 2'6" l x 3' h (Denver)

101-E TCA Scrubber with 3 Beds
13,000 SCFM of gas
Gas Velocity 12.5 ft/sec.
990 GPM @ 127°F of 10 wt % limestone slurry
L/G = 55.0 GPM/MSCFM of inlet gas to Venturi
Removal efficiency: 90% of SO_2 removal using 3.5% sulfur coal (330 lbs/hr SO_2)
ΔP = 8" H_2O
1/4" Corten with Neoprene lining
Dimensions: 5'6" w x 5' l x 40' h (UOP)

102-F Scrubber Sump 5 minute retention
The Venturi and TCA Scrubber will be mounted on top of the sump
C.S. with polyester coating and 2" Kaocrete
Dimensions: 10' w x 5' l x 40' h (UOP)

101-F TCA Recirculation Tank 5 minute retention
5328 gal. of 10 wt % limestone slurry
3/16" C.S., rubber lines, open top, 1/4" flat bottom
Dimensions: 10' dia. x 10' h (Smith Industries)

101-J TCA Recirculation Pump and Drive
2 at 100% capacity (1 spare)
1050 GPM of 10 wt % limestone slurry @ 127°F
Centrifugal, outside, slide type maintenance base, rubber internals
HP = 40 ea.
Size: 8" suction 6" discharge
Dimensions: 5' w x 4' l x 4' h (Denver)

110-F Liquid Ammonia Storage Tank
30, 15 minute adjustments
160 gal. @ 175°F, 350 psig
Horizontal pressure vessel with a u-tube heating coil (1/2" d x 4" l) for heating the ammonia. Nozzles, safety equipment, 2 elliptical heads
Dimensions: 2'6" w x 4'6" l (Wyatt)

110-B Direct Fired Gas Reheater
622,000 BTU/Hr
13,300 SCFM from 127°F to 200°F
Oil burner type using No. 2 fuel oil
Dimensions: 5' w x 6' l x 2'6" h (John Zink Co.)

105-J Fuel Oil Pump and Drive
1.0 GPM of No. 2 fuel oil
Vertical, inline
HP = 5.0
Size: 2" suction x 1-1/2" discharge
Dimensions: 6" w x 15" l x 30" h (Ingersoll-Rand)

108-F Fuel Oil Storage Tank (30 day supply)
8640 gal. of No. 2 fuel oil
3/16" C.S. Cone Roof, 1/4" flat bottom
Dimensions: 11' dia. x 14' h

108-J Fuel Oil Loading Pump
4.0 GPM of No. 2 fuel
Vertical, inline
HP = 5.0
Size 2" suction, 1-1/2" discharge
Dimensions: 6" w x 15" l x 30' h

113-J Induced Draft Fan

18,250 ACFM @ 200°F for 30 in. H_2O differential pressure
HP = 125
Single inlet, St. S. flanged inlet and outlet connections, wear strip, split housing, access door, drain connections
Dimensions: 68" w x 44" l x 72" h (Buffalo Forge)

Ductwork

142'3" of square duct 2'3" x 2'3"

Inlet Gas Duct to Venturi	42'6"
Duct from TCA Scrubber	6'3"
to Entrainment Separator	3'0"
From Reheater to I.D. Fan	5'3"
From Reheater to I.D. Fan	63'0"
From I.D. Fan to Stack	5'0"
From I.D. Fan to Stack	10'0"
From I.D. Fan to Stack	2'0"
By-Pass From Inlet to Outlet Duct	5'3"

Transition Pieces

From TCA Scrubber to Duct 5'6" x 5' → 2'3"	6'3"
Duct to Entrainment Separator 2'3" x 2'3" → 6' x 6'	4'0"
Entrainment Separator to Reheater 6' x 6' → 6' x 5"	7'0"
Reheater to Duct 6' x 5' → 2'3" x 2'3"	5'3"

100-G Venturi Damper

for 2'3" x 2'3" duct
Opposed blades, multi-louvre with actuator installed in inlet duct to Venturi (Buffalo Forge)

104-L TCA Recirculating TK Agitator

For 101-F to maintain solids suspension
Open-type agitator with worm-gear reducer drive mechanism
Speed: 900 ft/min. HP = 10.0
Dimension: 10'1" dia. x 12'4" h (Denver)

102-L Horizontal 2 Stage Entrainment Separator

13,000 SCFM at 8 ft/sec.
Wash water 5 gm/ft^2 of cross sectional area
The complete unit will include a casing (housing) built-in collecting tank, spray nozzles, baffles, chevron type eliminator blades and all internal piping
Dimensions: 6' x 6' x 6' (UOP)

107-F Entrainment Separator Recirculation Tank

5 minute retention
888 GPM of water
3/16" C.S. (coal tar epoxy coated), open top
1/4" flat bottom. A baffle in the tank divides the chamber into two equal parts.
Dimensions: 6' dia. x 6' h (Smith Industries)

107- 1st Stage Entrainment Separator Recirculation Pump and Drive

2 @ 100% capacity (1 spare)
178 GPM of water
Vertical, inline
HP = 10
Size: 3" suction x 2" discharge,
Dimensions: 6" w x 17" l x 43" h (Ingersoll-Rand)

108-J 2nd Stage Entrainment Separator Recirculation Pump and Drive

2 @ 100% capacity (1 spare)
160 GPM of water
Vertical, inline
HP = 10
Size: 3" suction, 2" discharge,
Dimensions: 6" w x 17" l x 43" h (Ingersoll-Rand)

101-G By-pass Damper

For 2'3 x 2'3" by-pass duct from inlet to outlet duct.
Guillotine type with actuator (Buffalo Forge)

102-G Fan Damper

For 2'3" x 2'3" outlet duct to stack.
Opposed blade, multi louvre with actuator (Buffalo Forge)

103-G Inlet Box Fan Damper

To be installed in the inlet fan box
Box dimension 14 1/4" x 59"
Parallel blade

B. Limestone Handling and Slurry Preparation

Stock-pile 30 day supply
288 tons 3/4" crushed limestone
Dimensions: 38' dia., 19' Hi

108-L Stock-pile Feeder

2.4 TPH, vibrating feeder. Complete with hopper.
Openings 3' dia and 6" dia. at the bottom.
Dimensions: 3'10" x 3'10", 2'7" deep (Vibranetie)

101-V Limestone Silo Conveyor

Belt conveyor, 18" wide, 145 ft. long.
16 ft. horizontal
129 ft. at 20° for 44' vertical lift.
Capacity 2.4 TPH (Hi-Line)

103-F Limestone Storage Silo (1 day supply)

9.6 tons
Atmospheric pressure and temperature. Two cones.
1/4" shell, 3/8" bottom carbon steel.

104-F Ball Mill Surge Tank

4.5 GPM of 60 wt % limestone slurry.
80°F, atmospheric pressure
3/16" C.S., coal tar expoxy coated, 1/4" flat bottom.
Dimensions: 3'diam., 3' H

102-J Limestone Slurry Transfer Pump & Drive

2 at 100% capacity
1.5 GPM of limestone slurry
HP = 10
Centrifugal, rubber internals
Size: 1 1/2" suction, 1 1/4" discharge
Dimensions: 2' W, 2'7" L, 2' H

114-J Ball Mill Air Compressor

50 ACFM @ 120 psig
460 volt, single stage.
Dimensions: 2'9", 4'5" long, 5' H

C. Waste Disposal, Settling Pond

109-F Slurry Over-flow Surge Tank

13.0 GPM of 19 wt % limestone slurry @ 80°F
3/10" C.S. coal tar epoxy coated, open top
1/4" flat bottom.
Dimensions: 3' diam., 3' H (Maloney-Crawford)

104-J Slurry Over-flow Transfer Pump & Drive

2 pumps @ 100% capacity (1 spare)
13.8 GPM of 19 wt % limestone slurry @ 127°F rubber internals
HP = 10
Size 1 1/2" suction, 1 1/4" discharge
Dimensions: 2' W, 2'7" L, 2' Hi (Denver)

112-J Tunnel Sump Pump

5GPM

105-F Limestone Slurry Hold Tank (1 day supply)

2160 Gal of 60 wt % limestone slurry

3/16" C. Stl open top, 1/4" flat bottom, rubber lined

Dimensions: 7' dia., 7' H (Smith Industries)

105-L Limestone Slurry Tank Agitator

For 105-F Open type Agitator with axial-flow propeller and worm-gear reducer drive.

Speed = 900 ft/min, HP = 15

Dimensions: 7'3" dia., 8'10" H.

103-J Limestone Slurry Feed Pump & Drive

2 at 100% capacity (1 spare)

4.1 Gal of limestone slurry.

HP = 10

Centrifugal, rubber internals.

109-L Limestone Weigh Feeder

Two 600 lbs/hr max., 400 lbs/hr min.

12" width, 35" length.

Gravimetric feeder with digital controller.

(Merrick)

106-L Ball Mill Wet Grinder

2 mills at 100% capacity

Capacity 9.6 TPH

33 RPM HP = 15

3/4" limestone to a product size of 70% minus 200 mesh.

Dimensions: 3' dia., 9'9" long, 6' H (Denver)

106-F Process Water Surge Tank

25.0 GPM of water at 80°F
3/16" C.S. coal tar epoxy coated, open top
1/4" flat bottom.
Dimensions: 3' dia., 3' H. (Maloney-Crawford)

106-J Process Water Pump & Drive

2 @ 100% capacity (1 spare)
38.0 GPM of water
HP = 15
Vertical, in-line
Size 2" suction, 1 1/2" discharge
Dimensions: 8" wide, 17" long 44" H.

111-J Emergency Process Water Pump & Drive

38.0 GPM of water
HP = 15
Vertical, in-line
Size 2" suction, 1 1/2" discharge
Dimensions: 8" wide, 17" long, 44" H.

Settling Pond 15 yrs capacity

2.3 acres, 50' deep
80% service factor
Dimensions: 317' x 317' W x 50' H.

APPENDIX G

SAMPLE CALCULATION OF COST OF SNG AND SRC

Total annual cost of production has been related to total plant investment (TPI). Total plant investment includes bare cost (including contingency) of the plant, taxes and insurance, and contractor's overhead and profits. Contingency has been considered equal to zero. Total annual cost of production is given by

$$TAC = 0.225\ TPI + 2.1\ TO \cdot CO\ (1 + F) + 1.04\ ANR$$

where

TO = Total number of plant operators
300 for SNG; 200 for SRC
CO = Unit cost of operating labor ($7.00/hr)
F = Location factor
ANR = Annual cost of raw materials, utilities, waste disposal less by product credit

A summary of procedures to calculate cost of production of SNG and SRC is as follows for a plant capacity of 250 x 10^9 Btu/day.

SNG Plant:

Cost of the equipment (E) is related to the carbon and sulfur content of coal. When the carbon and sulfur content of the coal do not affect equipment size, fixed costs have been used. Equipment costs have been divided into the category of solid handling and chemical processing plant and multiplied by a fixed multiple (C) to get total plant investment. The value of C varies from 2.4 to 3.1 for solid handling and 3.3 to 4.2 for a chemical processing plant for location factors between 1.0 (Gulf Coast) and 2.0.

Equipment costs for an SNG plant are as follows:

1. Coal Preparation and Handling
   $E1 = 2100$ M\$
2. Fine Agglomeration
   $E2 = 5000 - 100\ (PCARB-65)$ M\$
3. Coal Gasification
   $E3 = 14800 + 160\ (PCARB-65)$ M\$
4. Shift Conversion and Gas Cooling
   $E4 = 4500$ M\$
5. Gas Purification by the Rectisol Process
   $E5 = 1300 + 200\ PSULF$ M\$
6. Methane Synthesis
   $E6 = 5500$ M\$
7. SNG Compression
   $E7 = 3000$ M\$
8. Oxygen Plant
   $E8 = 9700 + 160\ (PCARB-65)$ M\$
9. Phenosolvan Unit
   $E9 = 1800$ M\$
10. Furnace Stack Gas Scrubbing and Plant Sulfur Recovery
    $C10 = 1250\ PSULF + 1065\ (TDAFC \cdot PSULF)^{0.6}$ M\$
11. Utility Plant
    $E11 = 13800 + 200\ (PCARB-65)$ M\$
12. Other Offsites
    $E12 = 14000$ M\$

where

PCARB = percent carbon in coal on dry ash free basis
PSULF = percent sulfur in coal on dry ash free basis
TDAFC = total dry ash free coal requirement for a 250×10^9 Btu/day SNG plant

For evaluating Total Plant Investment, sections 1 to 3 fall under the category of coal handling plant while the remaining sections are chemical processing plants.

The total dry ash free coal requirement for a 250 x 10^9 Btu/day SNG plant is given by:

$$TDAFC = 1.51 - 0.0156\ (PCARB-65)\ \text{million lb/hr}$$

The total as received coal requirement (TCOAL) of a 250 x 10^9 Btu/day SNG plant is given by:

$$TCOAL = 100\ TDAFC/(100 - PH20 - PASH)\ \text{million lb/hr}$$

Annual cost of raw materials, utilities less by product credit (ANR) is given by:

$$ANR = ACOAL + ACHEM - ASULF$$

where, ACOAL is annual cost of coal feed to the plant and is given by:

$$ACOAL = 12 \times CCOAL \cdot TCOAL \cdot SD\ \text{M\$/yr}$$

ACHEM is annual cost of catalyst and chemicals, assumed constant at 1600 M$.
ASULF is the annual credit for the sale of sulfur. It is assumed that 80% of the sulfur in coal is recovered as by-product and is given by:

$ASULF = 0.1\ CSULF \cdot TDAFC \cdot PSULF \cdot SD$ M$/yr.
CCOAL = Unit cost of coal feed to plant in $/ton
CSULF = Unit credit for sulfur in $/ton
SD = Number of days the plant is on stream per year (330 days)

Example: Coal from Jefferson mine, Walker county in Alabama.

Location Factor = 1.2 (for Alabama)

Coal details: Bituminous PCARB = 83.2; PSULF = 1.64
PH20 = 4.1; PASH = 4.2

TDAFC = 1.51 - .0156 (83.2-65) = 1.23 million lb/hr
TCOAL = 100 x 1.23/(100-4.1-4.2) = 1.34 million lb/hr
Cost of coal = $12.80/ton

Scale up factor (C) to evaluate total plant investment
C = 2.57 solid handling, section 1 to 3
C = 3.46 chemical processing, section 4 to 12

Section	E, M$	TPI, M$
1	2100	5397
2	3180	8173
3	17712	45520
4	4500	15570
5	13328	46115
6	5500	19030
7	3000	10380
8	12612	43638
9	1800	6228
10	3423	11842
11	17440	60342
12	14000	48440

TPI = 320675 M$
ACOAL = 12 x 12.80 x 1.34 x 330 = 67922 M$
ASULF = 0.1 x 10 x 1.23 x 1.64 x 330 666 M$

ANR = 67922 + 1600 - 666
= 68856 M$

$$\begin{aligned} TAC &= 0.225\ TPI + 2.1\ TO\cdot CO\ (1 + F) + 1.04\ ANR \\ &= 0.225 \times 320675 + 2.1 \times 300 \times 7 \times 2.2 + 1.04 \times 68856 \\ &= \$153.464 \text{ million} \end{aligned}$$

Annual Gas Production = 82.5 million MMBtu/year
Cost of Production = 153.464/82.5
= $1.86/MMBtu

SRC Plant:

The total plant investment for a plant producing 250×10^9 Btu/day of solvent refined coal is given below

Section Number	Section Description	Total Plant Investment (TPI) M$ for F=1.0
1	Coal preparation (solid handling section)	10,000
2	Preheater/dissolvers	40,000
3	Ash filtration, drying and disposal	15,000
4	Solvent/light oil/cresylic acid recovery	30,000
5	Product solidification/ handling and storage	10,000
6	Hydrogen plant	10,000
7	Sulfur removal from fuels and sulfur recovery	10,000
8	Steam and power generation	10,000
9	Other offsites	30,000
		165,000

If F = 2.0, the value of TPI is $215 million.

The annual cost of raw materials, utilities, less by-product credits (ANR) is given by:

$$ANR = ACOAL + ACHEM - ASULF - ACRES$$

ACOAL is the annual cost of coal feed to the plant in M$. It is assumed that 80% of heating value in coal is recovered as SRC.

ACHEM is the annual cost of catalyst and chemicals and is assumed constant at 500 M$.

ASULF is the annual credit for by product-sulfur. It is assumed that 40% of the sulfur in coal is recovered as by product.

ACRES is the annual credit for the sale of cresylic acid. It is assumed that 170 tons/day of cresylic acid is obtained as by product and sells for $100/ton.

Example: Coal from Jefferson mine, Walker county in Alabama

Location Factor = 1.2

Total Plant Investment = 175092 M$

Coal Details: Bituminous PCARB = 83.2, PSULF = 1.64
PH20 = 4.1 , PASH = 4.2
HHV = 13590 Btu/lb as received
Unit cost = $12.80/ton

$$\text{Coal feed} = \frac{250 \times 10^9}{13590 \times 0.8 \times 2000} = 11500 \text{ tons/day}$$

By-Products: Sulfur = 11500 x 0.015 x 0.4 = 61 LT/day @ $10/LT
Cresylic Acid = 170 tons/day @ $100/ton

ACOAL = 11500 x 12.80 x 330 = 48576 M$
ASULF = 61 x 10 x 330 = 201 M$
ACRES = 170 x 100 x 330 = 5610 M$
ACHEM = Cost of catalysts and chemicals = 500 M$

ANR = 48576 + 500 - 201 - 5610
= 43265 M$

TAC = 0.225 x 175092 + 2.1 x 200 x 7 (1+1.2) + 1.04 x 43265
= $90.86 million/year

Annual SRC production = 250×10^9 x 330 Btu
= 82.5 million million Btu

Cost of SRC = $90.86/82.5 MMBtu
= $ 1.10/MMBtu

APPENDIX H

SAMPLE CALCULATION OF COST OF INTERMEDIATE BTU GAS

Example:

Location: Alabama F = 1.2

Coal Details: Bituminous PCARB = 83.2%, PSULF = 1.64%
PH20 = 4.1%, PASH = 4.2
COAL = $12.80/ton

Other Information:

SD = 330 CSULF = $10/ton CO = $7/hour

Derived Information:

C = 2.57 Section 1 to 3
C = 3.46 Section 4 to 10

TDAFC = 0.651 - 0.0067 x (83.2 - 65) = 0.529 million lb/hr

Section	EMS	TPI M$
1	1250	3213
2	1650	4240
3	7684	19748
4	800	2768
5	1400	4844
6	6416	22200
7	920	3183
8	204	706
9	8592	29728
10	6500	22490
		113120

TPI = $113.12 million

TCOAL = 0.529/0.917 = 0.577 million lb/hr

ACOAL = 12 x 12.80 x 0.577 x 330 = 29247 M$

ASULF = 0.1 x 10 x .529 x 1.64 x 330 = 286 M$

ANR = 29247 + 400 - 286 = 29361 M$

TCR = 1.21 x 113120 + 0.8 x 150 x 7 (1 + 1.2) + 0.4 x 29361

TCR = $150.5 million

TAC = 0.225 x 113120 + 2.1 x 150 x 7 (1 + 1.2) + 1.04 x 29361

TAC = $60.84 million

AGP = 125 x 10^9 x 330 = 41.25 million MMBtu/year

The gas cost = 60.84/41.25 = $1.47/MMBtu

APPENDIX I

SAMPLE CALCULATION OF COST OF LOW BTU GAS

Example:

Location: Alabama F = 1.2

Coal Details: Bituminous PCARB = 83.2%, PSULF = 1.64%
PH20 = 4.1%, PASH = 4.2%
CCOAL = $12.80/ton

Other Information:

SD = 330 CSULF = $10/ton CO = $7/hour CPOWER = 8 mils/KWH

Derived Information:

C = 2.57 Section 1 to 3
C = 3.46 Section 4 to 10

TDAFC = 0.683 - .0071 (83.2-65) = 0.554 million lb/hr

Section	EM$	TPI M$
1	1300	3341
2	1730	4446
3	8356	21475
4	700	2422
5	1780	6159
6	950	3287
7	228	789
8	6550	22663
9	1214	4200
10	6000	20760
		89542

TPI = $89.542 million

TCOAL = 0.554/0.917 = 0.604 million lb/hr

ACOAL = 12 x 12.80 x 0.604 x 330 = 30616 M$

ASULF = 0.1 x 10 x 0.554 x 330 = 183 M$

ACHEM = 420 M$

APOWER = 1.1 x 8 x 330 = 2904

ANR = 30616 + 420 - 183 - 2904 = 29749 M$

TCR = 1.21 x 89542 + 0.8 x 150 x 7 (1+1.2) + 0.4 x 27949

TCR = $121.4 million

TAC = 0.225 x 89542 + 2.1 x 150 x 7 (1+1.2) + 1.04 x 27949

TAC = 54065 M$

AGP = 125 x 10^9 x 330 = 41.25 million MMBtu

The gas cost = 54.065/41.25
= $1.31/MMBtu

APPENDIX J

NOMENCLATURE

AA	Annual cost of ammonia	M$/year
ACHEM	Annual cost of catalysts and chemicals	M$/year
ACOAL	Annual cost of coal feed	M$/year
ACR	Annual depreciation	M$/year
ACRED	Annual credit for by-products	M$/year
ACW	Annual cost of cooling water	M$/year
AE	Annual cost of electricity	M$/year
AF	Annual cost of fuel oil	M$/year
AFT	Annual federal income tax	M$/year
AH	Annual cost of steam	M$/year
AIC	Annual interest on debt and return on capital	M$/year
AL	Annual cost of limestone	M$/year
AML	Annual cost of maintenance labor and supervision	M$/year
AN	Annual cost of natural gas	M$/year
ANR	Annual cost of raw materials, utilities and waste disposal, less by-product credits	M$/year
AOC	Total net annual operating cost	M$/year
AOH	Annual cost of administration and overheads	M$/year
AOL	Annual cost of operating labor and supervision	M$/year
APOWER	Annual credit for power available for sale	M$/year
APS	Annual cost of plant supplies and replacement or Annual credit for purge solids	M$/year M$/year
AS	Annual cost of sodium carbonate	M$/year
ASA	Annual credit for recovered sulfuric acid	M$/year
ASC	Annual credit for recovered sulfur	M$/year
ASD	Annual credit for recovered sulfur dioxide	M$/year
ASULF	Annual credit for recovered sulfur	M$/year
ATI	Annual cost of local taxes and insurance	M$/year
AW	Annual cost of process water	M$/year
BARC	Bare cost of the control plant	M$

CA	Purchase price of ammonia	\$/ton
CCOAL	Unit cost of coal, as received	\$/ton
CCW	Unit cost of cooling water	\$/M gal
CE	Purchase (or transfer) price of electricity	mills/KWH
CF	Purchase price of fuel oil	\$/MM Btu
CH	Purchase (or transfer) price of steam	\$/M lbs
CL	Purchase price of limestone	\$/ton
CN	Purchase price of natural gas	\$/MSCF
CO	Unit cost of operating labor	\$/hour
CONC	Sulfuric acid mist concentration	wt. frac.H_2SO_4
$CONC_1$	Sulfuric acid plant product concentration	wt. frac.H_2SO_4
CONTIN	Contingency	
CPOWER	Unit cost of power	mills/KWH
CS	Purchase price of sodium carbonate	\$/ton
CSULF	Unit credit for recovered sulfur	\$/ton
CW	Unit cost of process water	\$/M gal
E	Total major equipment cost	M\$
EA	Major equipment costs, Wellman/Allied	M\$
EA1	Total major equipment costs related to scrubbing train, Wellman/Allied model for industrial boilers	M\$
EA1i	Major equipment costs related to the "i" th scrubbing train, Wellman/Allied model for industrial boilers	M\$
EA2	Major equipment costs related to the total gas flow to control plant, Wellman/Allied model for industrial boilers	M\$
EA3	Major equipment costs in the absorber area related to the sulfur flow to the control plant, Wellman/Allied model for industrial boilers	M\$
EC	Major equipment costs, wet limestone model, chemical processing equipment	M\$
EC1	Total major equipment costs related to scrubbing trains, wet limestone model for industrial boilers	M\$
EC1i	Major equipment costs related to the "i"th scrubbing train, wet limestone model for industrial boilers	M\$

EC2	Major equipment costs related to total gas flow to control plant, wet limestone model for industrial boilers	M$
EC3	Major chemical processing equipment costs related to the sulfur flow to the control plant, wet limestone model for industrial boilers	M$
EP	Major equipment costs, Wellman/Allied model, purge/make-up area	M$
ER	Major equipment costs, Wellman/Allied model SO_2 reduction area	M$
ES	Major equipment costs, Wellman/Allied model, SO_2 regeneration area or Major equipment costs, wet limestone model, solids handling equipment	M$ M$
F	Location factor	
FR	Sulfuric acid plant operating costs as a fraction of sulfuric acid value (VSA)	
GP	Total gas flow to the control plant	MACFM
GTi	Gas flow to the "i"th scrubbing train	MACFM
IDC	Interest during construction or Return on investment during construction	M$ M$
IF	Particulate index (=1 if particulates present in gas to control plant, =0 if partuculates absent)	
l	Life of control plant	years
L	Field labor costs	M$
LA	Field labor costs, Wellman/Allied model, absorber area	M$
LC	Field labor costs, wet limestone model, chemical process equipment	M$
LF	Load factor of the emissions source plant	
LP	Field labor costs, Wellman/Allied model, purge/make-up area	M$
LR	Field labor costs, Wellman/Allied model, SO_2 reduction area	M$
LS	Field labor costs, Wellman/Allied model, SO_2 regeneration area or Field labor costs, wet limestone model, solids handling equipment	M$ M$

M	Field material costs	M$
MA	Field material costs, Wellman/Allied model absorber area	M$
MC	Field materials costs, wet limestone model, chemical process equipment	M$
MP	Field materials costs, Wellman/Allied model, purge/make-up area	M$
MR	Field materials costs, Wellman/Allied model, SO_2 reduction area	M$
MS	Field materials costs, Wellman/Allied model, SO_2 regeneration area or Field material costs, wet limestone model, solids handling equipment	M$ M$
NA	Number of absorber trains	
NAT	Number of absorber trains, Wellman/Allied model for industrial boilers	
N7	Number of trains of sulfur-related equipment in the absorber and SO_2 regeneration areas, Wellman/Allied model	
N28	Number of equipment trains in the purge/make-up area, Wellman/Allied model	
P	Cost of limestone sludge settling pond	M$
PASH	Percent ash in coal feed, as received basis	
PCARB	Percent carbon in coal feed, dry ash-free basis	
PH20	Percent moisture in coal feed, as received basis	
PSULF	Percent sulfur in coal feed, dry ash-free basis	
r	Discounted cash flow rate of return on investment (fraction)	
RBi	Retrofit difficulty factor for boiler "r"	
RF	Retrofit difficulty factor for sulfuric acid plants	
RP	Retrofit difficulty factor for equipment in scrubbing section not in parallel trains, wet limestone and Wellman/Allied models for utility and industrial boiler plants	
S	Sulfur flow (From SO_2) to the control plant, Wellman-Lord model for sulfuric acid plants	lbs/hour

SD	Number of plant operating (stream) days per year	
SF	Total sulfur flow to the control plant	M lbs/hour
SM	Sulfur flow (from acid mist) to the control plant, Wellman-Lord model for sulfuric acid plants	lbs/hour
STC	Start-up costs	M$
S7	Total sulfur flow to control plant per train of sulfur-related equipment in the absorber and SO_2 regeneration areas, Wellman/Allied model	M lbs/hour
S28	Total sulfur flow to control plant per train of equipment in the purge/make-up area, Wellman/Allied model	M lbs/hour
TAC	Total annual production cost	M$/year
TCOAL	Total coal feed, as received basis	MM lbs/hour
TCR	Total capital required	M$
TO	Total number of shift operators	
TPI	Total plant investment	M$
VPS	Unit value of purge solids	$/ton
VSA	Unit value of sulfuric acid	$/ton
VSC	Unit value of recovered sulfur	$/long ton
VSD	Unit value of recovered sulfur dioxide	$/ton
WKC	Working capital	M$

FIGURE 6.10
CUMULATIVE ANNUAL PRODUCTION COST OF
STACK GAS SCRUBBING IN
EXISTING POWER PLANTS
(SUMMATION IN ORDER OF DECREASING PLANT POWER PRODUCTION)

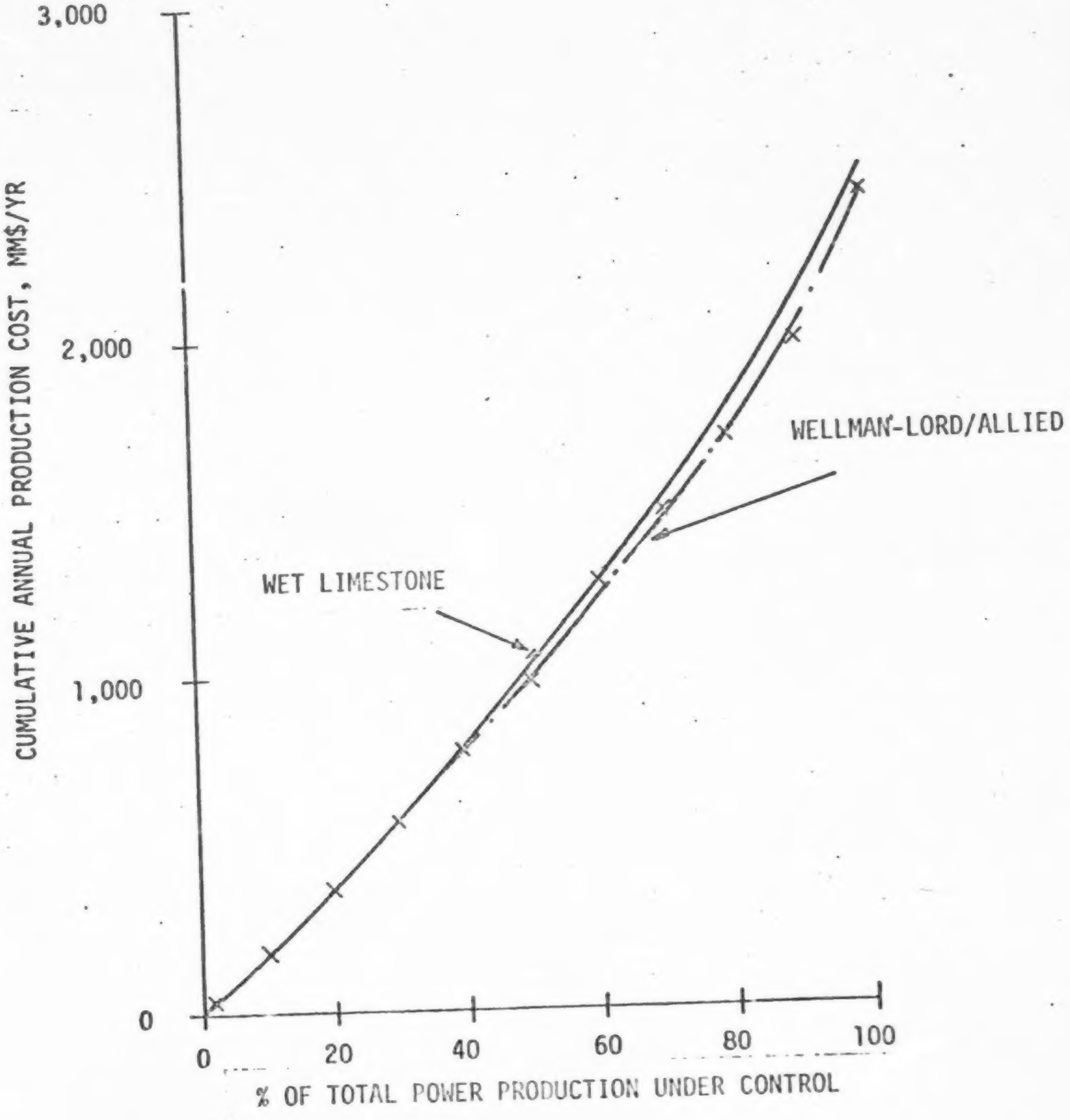


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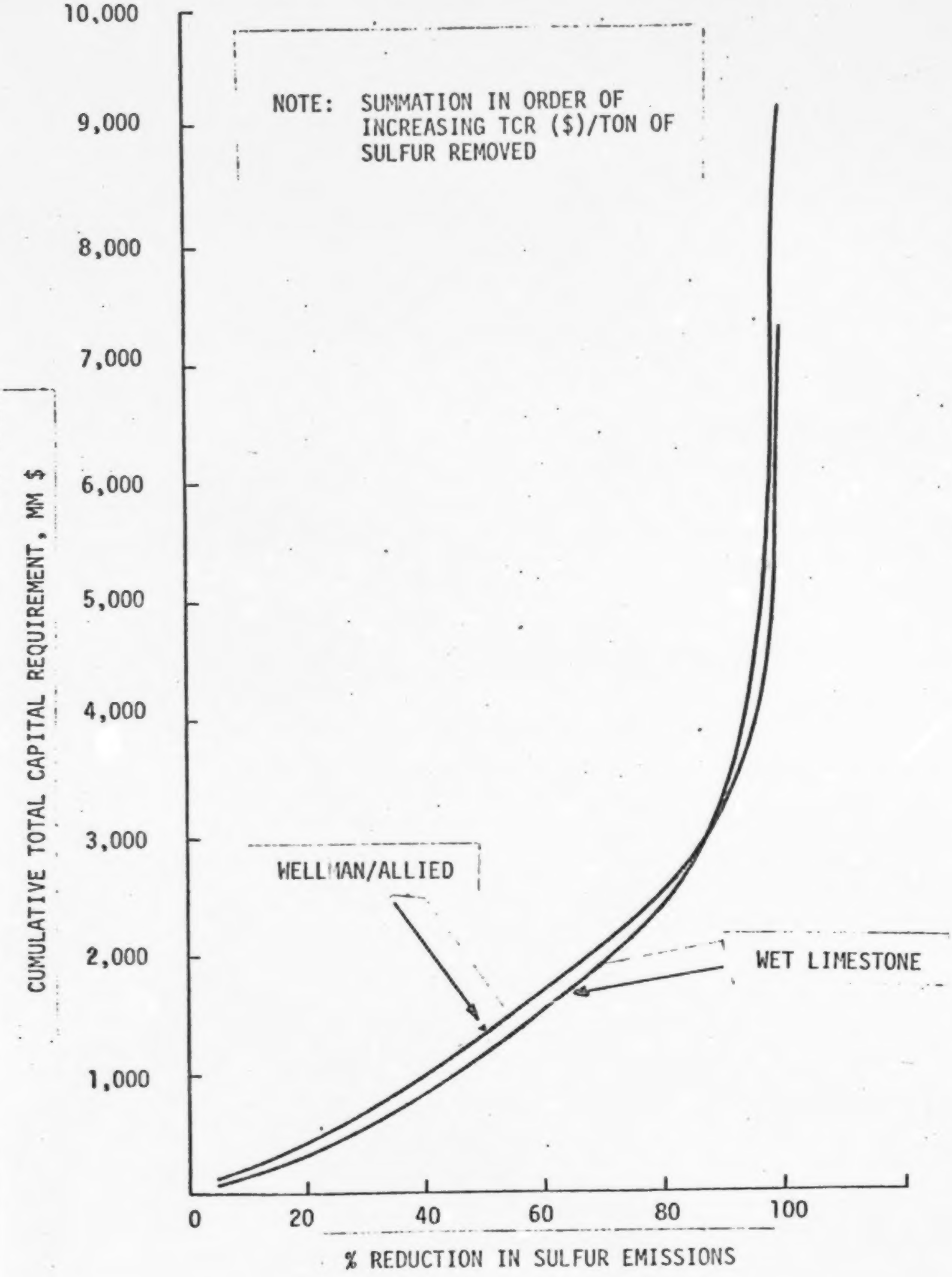
FIGURE 6.11

CUMULATIVE TOTAL CAPITAL REQUIREMENT FOR REDUCING SULFUR EMISSIONS FROM EXISTING POWER PLANTS



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